AOSTRA

OIL SANDS 2000

Energy·Environment·Enterprise

Hilton International Hotel • Edmonton, Alberta, Canada

March 26, 27 and 28, 1990

Preprints

Organized by:

ALBERTA OIL SANDS TECHNOLOGY AND RESEARCH AUTHORITY

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A MESSAGE FROM THE CHAIRMAN OF AOSTRA

Dear Registrant:

In this binder you will find:

(1) a complete program for the Conference;

(2) a Table of Contents listing the authors and titles for all the papers that will be presented at the Conference;

(3) preprints of the complete manuscripts of all papers that were available at the time of printing.

I hope that you will find our OIL SANDS 2000 Conference a truly rewarding experience, and that you will share with us the enthusiasm we feel for the future of our vast hydrocarbon resources.

William J. Yurko
Chairman and Chief Executive Officer
Alberta Oil Sands Technology and Research Authority

OIL SANDS 2000
ENERGY - ENVIRONMENT - ENTERPRISE

HILTON INTERNATIONAL HOTEL - EDMONTON
MARCH 26-28, 1990

- PROGRAM -

MONDAY, MARCH 26, 1990

3:00-9:00 p.m.	REGISTRATION Foyer, Hilton Ballroom
3:00 p.m.	TECHNOLOGY DISPLAY OPENING Second Level, Hilton Hotel
6:30-9:30 p.m.	RECEPTION Foyer - Second Level, Hilton Hotel

TUESDAY, MARCH 27, 1990

7:00-8:00 a.m.	SPEAKERS' BREAKFAST MacKenzie Suite
7:30-8:30 a.m.	REGISTRATION Foyer, Hilton Ballroom

CONFERENCE BEGINS

8:30-8:45 a.m.	**OPENING REMARKS** **THE HON. RICK ORMAN, Minister of Energy, Alberta** Hilton Ballroom
SESSION 1	**A GLOBAL FORECAST FOR OIL SANDS AND HEAVY OIL DEVELOPMENT** Chairman: Mr. W.J. Yurko, AOSTRA Co-Chairman: Dr. E.J. Wiggins, AOSTRA
8:45 a.m.	**Future in Alberta for Oil Sands and Heavy Oils** Dr. B. Mellon, Deputy Minister, Executive Council, Alberta
9:05 a.m.	**Some Global Factors Affecting the Potential of Heavy Crude and Tar Sands** Mr. M.A. Carrigy, UNITAR/UNDP Centre for Heavy Crude and Tar Sands
9:25 a.m.	**AOSTRA's International Activities** Dr. D.A. Redford, AOSTRA
9:45 a.m.	QUESTION PERIOD
10:00 a.m.	COFFEE BREAK

SESSION 2	**FUTURE TECHNOLOGIES FOR MINING AND EXTRACTION OF OIL SANDS** Chairman: Mr. G.R. Gray, Consultant Co-Chairman: Mr. D.P. Komery, AOSTRA
10:30 a.m.	**Dredging and Cold Water Extraction Process for Oil Sands** Dr. W. Jazrawi, Esso Resources Canada Limited
10:50 a.m.	**The SESA Process for the Recovery of Bitumen From Mined Oil Sands** Dr. B.D. Sparks, National Research Council, Dr. G.W. Govier, Consultant
11:10 a.m.	**Oil Sands Extraction: A Dynamic Technology** Mr. J.A. Stone, Mr. A.W. Hyndman, Dr. J.E. Clark; Syncrude Canada Ltd.
11:30 a.m.	QUESTION PERIOD
11:45 a.m.	LUNCHEON - RUTHERFORD SUITE, Lobby Level
1:00 p.m.	**KEYNOTE SPEAKER: MR. B.B. ROMBOUGH, Chairman, PanCanadian Petroleum Limited and Chairman, Canadian Petroleum Association** Hilton Ballroom
SESSION 3	**NEW METHODS FOR ACCESSING RESERVOIRS** Chairman: Dr. T. Nasseri, Centre for Frontier Engineering Research Co-Chairmen: Dr. R.W. Luhning, AOSTRA; Dr. M.D. Everell, Energy Mines and Resources Canada
1:45 p.m.	**AOSTRA Underground Test Facility - Achievements and Future Development** Mr. J.A. Haston, Mr. N.R. Edmunds, Dr. R.W. Luhning, Mr. J.C. O'Rourke, AOSTRA
2:05 p.m.	**The Use of Horizontal Wells Drilled from the Surface for the Recovery of Bitumen, Heavy Oil, Conventional Oil and Gas** Dr. R.M. Butler, University of Calgary
2:25 p.m.	**Advances Made in Borehole Hydraulic Mining Technology for Bitumen Recovery From Athabasca Oil Sands** Mr. R. Paul, Mr. M. To, Esso Resources Canada Limited
2:45 p.m.	QUESTION PERIOD
3:00 p.m.	COFFEE BREAK

SESSION 4 — **ADVANCES IN UPGRADING TECHNOLOGY**

Chairman: Dr. F. Otto, University of Alberta
Co-Chairman: Mr. R.T. Bailey, AOSTRA

3:20 p.m. — **Development of High Conversion Process for Alberta Bitumen**
Mr. L. Lewkowicz, Dr. B. Ozum, Mr. J. Meniuk, Alberta Research Council; Mr. M. Oguztoreli, Petro Simulator Systems Inc.; Mr. R.T. Bailey, Dr. T.J. Cyr, AOSTRA

3:40 p.m. — **Upgrading Shale Oils for the Australian Market**
Mr. J. Schmidt, Mr. B. Wright, Southern Pacific Petroleum NL.; Mr. M. Greene, Lummus Crest Inc.

4:00 p.m. — **Future Synthetic Crude Oil Quality**
Mr. T.J. McCann, RTM Engineering Ltd.

4:20 p.m. — **Demonstration of the High Conversion CANMET Hydrocracking Process on Cold Lake Vacuum Residuum**
Dr. B. Pruden, Dr. A.K. Jain, Petro-Canada Products; Mr. G. Muir, Lavalin Inc.

4:40 p.m. — QUESTION PERIOD

6:00 p.m. — RECEPTION - Foyer, Hilton Ballroom

6:45 p.m. — DINNER - Hilton Ballroom

FEATURED SPEAKER: DR. C.W. BOWMAN, President Alberta Research Council

SPECIAL GUESTS: THE HON. DON R. GETTY, Premier of Alberta and Mrs. Getty

WEDNESDAY, MARCH 28, 1990

7:00-8:00 a.m. — SPEAKERS' BREAKFAST - MacKenzie Suite

SESSION 5 — **UNLOCKING SUBSURFACE RESOURCES BY THERMAL RECOVERY**

Chairman: Mr. L. Milne; Husky Oil Operations Ltd.
Co-Chairman: Mr. W.K.. Good; AOSTRA

8:15 a.m. — **The Kearl Lake Pilot: Striving to be Number One in Athabasca In Situ Recovery**
Mr. D.H. Burger, Husky Oil Operations Ltd.; Dr. K.E. Kisman, AOSTRA

8:35 a.m.	**BODO; "Steaming into the Nineties"** Mr. D.W. Salahub, Mr. D.W. Mudie, Norcen Energy Resources Limited
8:55 a.m.	**Progress at Shell's Peace River In Situ Recovery Operation** Mr. J.I. Chambers, Mr. M.J. Zatka, Shell Canada Limited
9:15 a.m.	**Performance Evaluation of the Countess Fireflood Project** Mr. M. Metwally, PanCanadian Petroleum Limited
9:35 a.m.	QUESTION PERIOD
9:55 a.m.	COFFEE BREAK

SESSION 6 — **RECOVERING OLD OIL BY NEW ENHANCED RECOVERY METHODS**

Chairman: Dr. C. Ayasse; Petroleum Recovery Institute
Co-Chairman: Mr. J.D. Scott; AOSTRA

10:15 a.m.	**AWACT: Anti-Water Coning Technology** Mr. W.K. Freeborn, Mr. F.A. Skoreyko, Alberta Energy Company; Dr. R.W. Luhning, AOSTRA
10:35 a.m.	**CO_2 - Potential for EOR** Dr. S.M. Farouq Ali, University of Alberta; S.B. Dyer, Saskatchewan Research Council
10:55 a.m.	**Carbon Dioxide Miscible Flooding Experience in the Joffre Viking Field** Mr. D.J. Stephenson, Vikor Resources Ltd.
11:15 a.m.	**Bacteria to Control Conformance of a Waterflood** Dr. J.W. Costerton, F. Cusack, H. Lappin-Scott, University of Calgary; Mr. M.J. Chmilar, Dr. T.J. Cyr, AOSTRA
11:35 a.m.	QUESTION PERIOD
11:55 a.m.	LUNCHEON - Rutherford Suite, Lobby Level
1:15 p.m.	**KEYNOTE SPEAKER: THE HON. RALPH KLEIN, Minister of Environment, Alberta** Hilton Ballroom

SESSION 7 — **LEAVING A CLEAN ENVIRONMENT**

Chairman: Mr. R. Clark; Alberta Special Waste Management Corporation
Co-Chairman: Mr. L.R. Turner; AOSTRA

2:00 p.m.	**Environmental Aspects of In Situ Recovery of Oil Sands and Heavy Oil** Dr. R.W. Luhning, Mr, L.R. Nelson, AOSTRA; Mr. D.L. Dabbs, Concord Scientific Corporation

2:20 p.m.	**The Shell/AOSTRA Produced Water Treatment Pilot Plant: "Testing The Limits"** Mr. G. Giesbrecht, CH2M Hill Engineering Ltd.; Mr. M. Padula, Shell Canada Limited
2:40 p.m.	**The AOSTRA Taciuk Process - The Flexible Alternative For Oily Waste Treatment** Mr. S. Goodwin, UMATAC Industrial Processes; Mr. L.R. Turner, AOSTRA
3:00 p.m.	QUESTION PERIOD
3:15 p.m.	COFFEE BREAK
3:35 p.m.	**Disposal of Tailings Sludge in Overburden Waste Dumps** Dr. E.R.F. Lord, Mr. T.P. Ostrowski, Syncrude Canada Ltd.
3:55 p.m.	**The Global Warming Problem** Dr. E.J. Wiggins, AOSTRA **Strategies for the Fossil Fuels Industries Under the Threat of Global Climate Warming** Dr. H.E. Gunning, Consultant, AOSTRA
4:15 p.m.	QUESTION PERIOD
4:25 p.m.	**CLOSING REMARKS** **MR. W.J. YURKO, Chairman and CEO, AOSTRA**
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Paper no. 11. ***Upgrading Shale Oils For The Australian Market.*** Jim Schmidt, Senior Process Engineer, and Bruce C. Wright, Executive Director, Southern Pacific Petroleum NL, Sydney, Australia; Marvin Greene, Project Manager, ABB-Lummus Crest Inc., Engineering Development Center, 1515 Broad St, Bloomfield, New Jersey

Paper no. 12. ***Future Synthetic Crude Oil Quality.*** T.J. McCann, Vice President, RTM Engineering Ltd.

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Paper no. 23. ***The Shell/AOSTRA Produced Water Treatment Pilot Plant; Testing The Limits.*** Gary D. Glesbrecht, CH2M Hill Engineering Ltd., and Mario Padula, Shell Canada Limited

Paper no. 24. ***The AOSTRA Taciuk Process. The Flexible Alternative For Oily Waste Treatment.*** S. Goodwin, UMATAC Industrial Processes, A Division of UMA Engineering Ltd. (UMATAC), and L.R. Turner, Alberta Oil Sands and Technology Research Authority (AOSTRA)

Paper no. 25. ***Disposal Of Tailings Sludge In Overburden Waste Dumps.*** E.R. Lord and T.P. Ostrowski, Team Leader and Manager of Research Programs, Syncrude Canada Ltd. Research Department, Edmonton, Alberta

Paper no. 26. ***The Global Warming Problem.*** Ernest J. Wiggins, AOSTRA, Edmonton, Alberta; and ***Strategies For The Fossil Fuels Industries Under The Threat Of Global Climate Warming.*** Harry E. Gunning, HEG Consultants Ltd., Edmonton, Alberta

Future in Alberta For Oil Sands And Heavy Oils

Dr. B. Mellon, Deputy Minister, Executive Council

Paper no. 1

Paper not available at time of printing

Some Global Factors Affecting The Potential Of Heavy Crude And Tar Sands

M.A. Carrigy: UNITAR/UNDP Centre For Heavy Crude And Tar Sands

Abstract. The mission of the UNITAR/UNDP Centre for Heavy Crude and Tar Sands is to promote the development and utilization of the heavy crude and tar sand resources of the world through the collection, analysis and dissemination of information on all matters related to heavy crude and tar sands; and by facilitating cooperation between developing countries that are endowed with heavy crude and tar sand resources and countries, organizations and companies that can assist in the development of these resources.

In this paper, the Director of the Centre will discuss some of the global factors and special considerations that have to be taken into account when assessing the potential of heavy crude and tar sands to serve as alternative sources of liquid hydrocarbons.

Paper no. 2

Paper not available at time of printing

AOSTRA's International Activities

D.A. Redford

Introduction

Alberta Oil Sands are not only unique in their size, being the largest deposits in the world, but they are also unique in the wide variety of geological and petrophysical environments in which they are found. This has forced Albertans to develop a wide variety of recovery processes, novel equipment and hardware to enable the recovery of this resource. In short we have had to work harder and be innovative to win this resource. That we have been successful is apparent in the fact that ~1/3 of our oil currently originates from oil sands and that it is produced from a variety of different formations using a wide variety of recovery processes. Furthermore, the cost of this production continues to decline as new recovery technologies evolve.

The result of this development is that Alberta today is at the forefront of technology in heavy oil and oil sands recovery and processing. We are, however, not the only area in the world with significant heavy oil and oil sand resources. We are thus in an excellent position to export this technology around the world leading to major sales of goods and services from Alberta and employment for our citizens. AOSTRA who has played such a key role in fostering the development of this technology continues to work with it's partners, allies and associates and with the business community in general in promoting this technology around the world.

This paper outlines the world-wide resource of oil sands and heavy oil; reviews the way AOSTRA operates in the international market place and reviews the present state of development and opportunities in a number of countries which AOSTRA deals with.

The Resource

Oil Sands are found in many parts of the world (Figure 1). They are usually found at shallow depth, are predominantly asphaltic crudes and usually contain significant sulphur and some nitrogen. In most cases they are believed to be derived from lighter crudes by the action of sulphate reducing bacteria and hence are found or were formed in an area of active ground water flow. Heavy oils on the other hand may be found at any depth, may be asphaltic or paraffinic and in many cases may be immature crudes.

The designation of heavy oil and oil sands is a bit of a misnomer since as defined by the United Nations it involves both a density and a mobility factor. Hence, although crudes such as Athabasca are defined as oil sand, those from the Faja in Venezuela are defined as heavy oil even though the crudes are of similar nature and density. Despite this anomaly, for the purposes of this paper we have used the UNITAR definition and classified oil (tar) sands as that containing a bitumen with a gravity less than 20°API and a viscosity at reservoir conditions greater than 10,000 mPa·s while a heavy oil is one with a gravity less than 20°API but with a viscosity less than 10,000 mPa·s at reservoir conditions.

A summary of the resource is given in Table I. Definitions used in this table are as follows:

- **Oil in Place.** The gross volume of heavy oil or crude bitumen interpreted to exist in a reservoir before any volume has been produced.
- **Speculated Oil in Place.** Estimated quantities which have not been discovered but which general geological judgement suggests may exist.
- **Reserves (Established).** Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production; plus that judgement portion of contiguous recoverable reserves that are interpreted from geological, geophysical, or similar information, with reasonable certainty to exist.
- **Remaining Reserves.** Initial established reserves less cumulative production.
- **Speculative Reserves.** Estimated quantities which have not been discovered, but which general geological and engineering judgement suggests may be eventually economically obtainable.
- **Heavy Oil.** API gravity less than 20° and viscosity less than 10,000 mPa·s.
- **Oil Sands (Bitumen).** Viscosity greater than 10,000 mPa·s.

The sources of data are as follows. Canadian oil sands data were obtained from Alberta Energy Resources Conservation Board, heavy oil data from the Canadian Petroleum Association and literature from Richard Meyer of the U.S. Geological Survey.

U.S. Data were obtained from various literature written by Richard Meyer, Charles Masters and V.A. Kuuskraa.

USSR data were obtained from Meyer &

Meyerhoff (Geology of Heavy Crude Oil and Natural Bitumen in the USSR, Mongolia and China), Jim Yurko and Vladimir Reitman.

China data from Meyer & Meyerhoff.

Cuban data on known oil in place for heavy oil and oil sands from Brian Rottenfusser, Ecuador data from Meyer (World Resources of Heavy Oil and An Estimate of World Resources of Heavy Crude Oil and Natural Bitumen), plus additional information available to the author.

For other countries, the data obtained were from literature written by Meyer et al. (World Resources of Heavy Oil, An Estimate of World Resources of Heavy Crude and Natural Bitumen, and Heavy Oil Fields and Bitumen Deposits of the Middle and Far East and Oceania), Masters et al. (World Resources of Crude Oil, Natural Gas, Natural Bitumen & Shale Oil) and the UNITAR/UNDP Information Centre for Heavy Crude and Tar Sands (International Survey of Heavy Crude and Tar Sands).

A number of sources were available for each country. In cases where a particular study on that country was available, those figures on that country were used (e.g. Nigeria). In cases where figures from different sources were close, figures were averaged. Where figures did not coincide, most of the data used was from literature written by Richard Meyer.

Bitumen and heavy oil have often been thought of as a low quality resource and hence the data is often sparse, speculative or non-existent. In the Soviet Union for example, large amounts of both bitumen and heavy oil are believed to exist but these have been mainly unexplored due to the abundance of conventional crude. In China, large areas of their sedimentary basins remain unexplored while in Ecuador only the tip of the ice berg has been revealed in the limited drilling in the Pungaryacu deposit. While an attempt has been made to include some of these deposits under speculated bitumen or heavy oil in place, the values are probably understated and a number of countries have undoubtedly been left out.

AOSTRA International

Starting early after AOSTRA was formed, it became involved in international activities. Technology knows no boundaries and it became increasingly clear that if AOSTRA was to achieve its full potential it needed to draw technology from wherever it was found in the world as well as promoting AOSTRA and Alberta know-how and technology in the world market place.

Initially, when entering a foreign area, AOSTRA works to establish a joint interest, credibility and a relationship with a foreign country through government departments, agencies or government companies. When a mutual interest has been established this is usually formalized in a Memorandum of Understanding (MOU) which outlines the areas of common interest, the types of joint projects and cooperations that might take place and the general conditions under which such activities will occur. This MOU is then approved by the Canadian and foreign governments. Following the signing of an MOU, specific agreements are signed outlining the terms and conditions for each specific project, exchange or training activity.

Under terms of these MOU's and subsequent agreements, AOSTRA has conducted joint research projects in which work has been done partly in Canada and partly abroad, exchanged results of field pilots, exchanged scientists and engineers for periods of up to one year and provide on-the-job training for foreign specialists on AOSTRA projects. A list of countries with which AOSTRA has an MOU is given in Figure 1.

In addition to MOU activities, AOSTRA entertains proposals from companies around the world bringing new ideas for the recovery and processing of Alberta's petroleum resources and seeks to promote its technology world wide. These efforts have led to such activities as performance tests on Alberta bitumens and the design of an AOSTRA/Taciuk Processor for recovery of oil from Australian shales.

World Round Up

United States of America. The USA has limited oil sands resources but has significant heavy oil and large reserves of oil shale. It is a mature oil province with a large and growing demand for oil. It therefore represents both an area of technology importation as well as export. USA oil sands deposits tend to be oil wet and this has made them less attractive, however, processes such as the AOSTRA/Taciuk would handle this material. The process could also be extended to the rich diatomaceous deposits in California. The same process would also find application in processing Colorado shale although initial activities will be in the clean up of some of the 1200 EPA designated waste oil disposal sites.

AOSTRA/USA exchanges and joint projects take place in a wide variety of areas ranging from bitumen process testing to horizontal drilling and remote monitoring and AOSTRA will continue to operate both through its MOU with the DOE (Department of Energy) and with a wide number of private companies.

Latin America

Venezuela. Next to Canada, Venezuela has the largest reserves of heavy oil and tar sands in the world. These reserves exist both along the Bolivar Coast of Lake Maracaibo and in the vast deposits of the Faja. Venezuela has produced heavy oil for many years (e.g., the first steam stimulation project

in the world was in Venezuela) and has built up a vast bank of know-how and technology in the area. In recent years they have undertaken an extensive program of geological investigation and piloting which has resulted in a clear knowledge of the extent and nature of the resource plus demonstrated technology in recovery, transportation and upgrading. While production is currently on hold due to an abundance of light oil and limited OPEC quota it is estimated that Venezuela could produce 45 to 50 billion m^3 of bitumen using current technology. Because of the warm formations, high permeability and reservoir energy, current costs of producing bitumen from the Faja and delivering it to tide water are less than $3.50 Canadian per bbl. Principle means of production is steam stimulation with emulsions being used for transport.

AOSTRA has maintained excellent relationships with Venezuela for many years and has exchanged personnel, conducted joint projects and provided on the job training as well as cooperating with Venezuela in establishing and supporting the UNITAR/UNDP Information Center for Heavy Crudes and Tar Sands and its related activities.

Ecuador. Ecuador currently produces ~300 million/bbl per day of light crude from reserves of about 1.2 billion bbls. Discoveries of new reserves in the last few years have been discouraging with the result that production is anticipated to continue to decline leaving Ecuador a net importer of oil by the year 2000. Ecuador however has large (1 to 30 billion m^3) of heavy oil and bitumen which has not been exploited and has had very little exploration or characterization done. The deposits range from surface outcrops to unknown depths and range in thickness from 50 m to greater. In the decade ahead Ecuador will require major inflow of technology and equipment if it is to exploit these significant reserves.

Cuba. Along the overthrust zone along the north shore of Cuba are found heavy oil deposits in deep, thick, fractured carbonate pays of limited areal extent. Unfortunately these are often found under some of the finest beaches on the island. Cuba is currently producing ~20,000 bbl/day of this 16°API gravity crude but could produce substantially more with improved drilling technology and recovery methods. Long reach, directional and slant hole drilling would permit pad construction, thus offsetting wells from the beach and extending drilling offshore. Implementation of enhanced recovery would increase reservoir life beyond the few percent recovered obtained by primary production.

Cuba also has large "Marga" deposits. These are bitumen contained in a friable Marle which is about 70% carbonate. The deposits are very thick and rich but would have to be hydraulically mined as they are 300 to 400 meters deep.

In addition to the Marga deposits, Cuba has bitumen saturated carbonates and sands which outcrop at a number of locations near the north shore. While some of these are very rich and have been mined for road building material they are of limited extent and individually not large enough to support a surface oil sand type of recovery operation.

Trinidad. Trinidad has both heavy oil and oil sands deposits. Currently, heavy oil is being produced using steam stimulation methods from shallow (100 m) to moderately deep deposits. The oil sands occur in a rich massive sand about 100 m^3 thick and outcropping over an area of about 3.5 km^2. The deposit dips steeply to the south and a further 3.5 km^2 area could be mined down to 60 meters overburden. Reserves appear adequate to support a major oil sand recovery operation.

Eastern Europe

Hungary. While Hungary does not have extensive oil reserves it has had to work hard to squeeze recovery from those reserves it has and therefore has developed a variety of unique recovery processes. At its excellent Hydrocarbon Recovery Research Institute and in field tests they have developed a process for sustaining combustion in light oil reservoirs. AOSTRA is transferring this technology to Alberta to study its application here.

Hungary has also made excellent use of natural high pressure CO_2 reservoirs to conduct both miscible and immiscible displacements but also to conduct a unique CO_2 assisted gravity drainage recovery process.

Hungary has also had major success in using Controlled Source Audio-Frequency Magnet-Tellurics (CSAMT) methods for monitoring the progress of combustion fronts in in situ combustion projects and has developed high temperature gels for steam diversion or repair of damaged casing bonds.

AOSTRA has an active exchange program with Hungary and is exploring all these technologies.

Czechoslovakia. While Czechoslovakia has limited petroleum resources it does have two interesting heavy oil pools in Southern Czechoslovakia which may be amenable to Alberta technology. These pools are overlaid by gas and underlaid by water and may respond to gas or steam assisted gravity drainage to a horizontal well.

Czechoslovakia also currently mines oil shale which overlays coal seams. While the ore is not rich the fact that the ore is already mined may make it interesting.

Romania. Romania has two of the largest and most successful combustion projects in the world. The natural geological and petrophysical features of the

reservoirs plus the care and diligence in application of in situ combustion technology have been major factors in their success. The use of greaseless compressors has also greatly facilitated the operation and reduced formation damage. AOSTRA has obtained the results from these two successful field projects in exchange for the results from three combustion projects conducted in Canada.

One of Romania's large combustion projects takes place southwest of Bucharest on the Romanian plane and is displacing prime agricultural land. The use of Canadian slant well technology and pad construction would enable both industries to co-exist.

USSR. Oil production in the Soviet Union has grown dramatically since World War II (Figure 2) rising to 12.7 million bbls/day thus making the Soviet Union the largest oil producer in the world. Most of this spectacular growth has occurred as the result of the discovery of a number of giant oil fields which were relatively easy to drill and produce. In the process, heavy oil and tar sands deposits were largely ignored and thus while it is known that major deposits exist in the Soviet Union, they remain largely unexplored and undeveloped. In recent years the discovery rate of new conventional oil has declined sharply and this has renewed interest in unconventional crudes as well as in enhanced oil recovery. Canada, therefore, with its wealth of experience in both, is in an excellent position to assist the Soviet Union in this area by exporting technology and know-how and the related equipment and services.

AOSTRA is currently conducting an exchange of specialists with the Soviet Union. As a result of this exchange AOSTRA sees the opportunity for the application of its technology in a number of areas in the Soviet Union. In particular, the AOSTRA/Taciuk processor would have excellent application in oil sands recovery and in the clean up of oil spill and resid storage sites.

Despite its low emphasis on heavy oil and tar sands the Soviet Union has had some programs underway for some time. Notably are the Yarega project where shaft and tunnel access (SATAC) is used to recover heavy oil and projects in Kazakhstan where bitumen deposits are used for road paving. The Yarega deposit was visited early in the life of AOSTRA and led the way to the Underground Test Facility (UTF) which has been so successful in recovering bitumen from the Athabasca deposit.

Africa

Madagascar. AOSTRA has worked with Madagascar for some time in assessing the potential for recovering bitumen from the Bemolanga oil sands deposits. Initial work was in resource delineation and characterization and this was followed by tests using the AOSTRA/Taciuk processor. Results indicated that bitumen could be recovered from this resource but that the grade of the ore gave marginal economics. AOSTRA continues to work with Madagascar and is currently training and giving on the job experience to Madagascar specialists interested in establishing a petroleum information center.

Middle East

Turkey. Turkey has significant heavy oil reserves in deep fractured carbonate reservoirs. While some oil is produced by primary production, the majority is left in the ground. Miscible CO_2 flooding using naturally occurring CO_2 is being used in one reservoir, however, early breakthrough is limiting its effectiveness. Experimental steam stimulation pilots are also underway, however, the deep depth of the deposit may limit results. The use of AOSTRA/SATAC technology in combination with gravity stabilized vertical steam drive or steam assisted gravity drainage may prove to be effective technologies.

AOSTRA is currently completing an exchange of specialists with Turkey and developing plans for further MOU activities.

Jordan. Jordan has limited hydrocarbon resources. AOSTRA has joined with Petro-Canada International in assessing the potential of heavy oil shows in Eastern Jordan and in assessing the potential of oil sands deposits along the eastern bank of the Dead Sea.

The oil sand deposits have the potential for supplying modest amounts of energy to Jordan using a process such as the AOSTRA/Taciuk Process, however, considerably more test drilling is required to define the resource.

Asia

China. China is a relatively new oil producing area. It has large sedimentary basins, mainly underexplored, and production is likely to expand from the current 2 million/day level. It currently produces about 200 thousand bbl/day of heavy crude from four main fields — Karamay, Liaohe, Shengli and Nanyang. All production is by steam stimulation with the paraffinic crudes in Liaohe, Shengli and Nanyang responding well, yielding excellent steam oil ratios.

The shallow Nanyang field is located in prime agricultural land. The recent introduction of Canadian slant hole technology should enable exploitation of this field with minimum disturbance to the farm land and rural villages.

The fields at Liaohe and Shengli are at considerable depth (1000 m) and insulated tubing is used to achieve steam injection. The Liaohe field is located in a coastal flood plane and would respond well to the introduction of Canadian technology for pad construction and directional drilling.

The Karamay fields are located in a very harsh

environment in the far northwest of the country. Here the paraffinic crude is recovered by steam stimulation using a complex surface distribution of insulated pipes. Canadian technology for operating in harsh environments including the use of pad construction and directional drilling would greatly facilitate operations.

China has one true oil sands deposit, Pengcheng, located near Karamay in Xinjiang province. This deposit is currently unexploited but may respond well to in situ methods successful in Athabasca. In particular, the use of SATAC technology coupled with gravity drainage to horizontal wells may be very successful.

AOSTRA has had MOU's with China for a number of years and has conducted a number of joint projects, technology and personnel exchanges.

Currently AOSTRA has MOU's with the major heavy oil fields as well as with RIPED, the central research group for the petroleum industry and with the Chinese National Petroleum Corporation (CNPC). Under terms of these MOU's AOSTRA has undertaken 9 projects and has joined in sponsoring a Heavy Oil Symposium in China. A Second Symposium is to take place in China in October 1990.

India. India produces about 600,000 bbls/day of oil with the majority coming from offshore (Bombay area) and from Assam. There is only one major heavy oil deposit, Mehsana, located in Gujerat state which contains 150 million m^3 of oil. It consists of fluvial unconsolidated sand 10 to 20 meters thick located at a depth of 1000 m. It is a long thin reservoir (32 km by 3 km) with a strong edge water drive. Primary recovery from this reservoir recovers only a small portion of the oil in place. Two in situ combustion pilots are currently completing construction.

AOSTRA has initialled an MOU with India and anticipates cooperation with the Institute for Reservoir Studies (IRS, located in Ahmedabad) on enhanced recovery projects. AOSTRA is also working with Oil India on the potential use of the AOSTRA/Taciuk Processor to clean up sludge disposal pits at refinery sites.

Concluding Remarks

AOSTRA's international program is primarily involved with technology transfer. Obtaining good ideas, concepts and experience wherever it may be found in the world and using it to assist in fulfilling AOSTRA's mandate to develop the technology which will permit the recovery and processing of Alberta's hydrocarbon resources. It is also technology transfer abroad and in the process achieving technology sales for AOSTRA, its allies, associates and partners and as a vehicle for promoting Alberta petroleum technology and the resulting export of goods and services.

Technology transfer is first and foremost people. AOSTRA has therefore emphasized personnel exchanges and training as key components of its international program.

Acknowledgments

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Table 1. Heavy oil and oil sand resources around the world

	HEAVY OIL (x 10^6 m^3)					OIL SANDS (x 10^6 m^3) Page 1				
	Oil in Place		Reserves			Oil in Place		Reserves		
	Known	Speculative	Cumulative Production	Remaining	Speculative	Known	Speculative	Cumulative Production	Remaining	Speculative
N. AMERICA										
United States	15,103	9540	1590	3180	3816	3660	3137	0.14	1110	320
Canada	2780	3184	163	88	560	267,000	133,000	9,085	566	39,172
Mexico	6675	2544		650	254					
CENTRAL & LATIN AMERICA										
Argentina	627	2613	11	56	277					
Brazil	520	1590	0.7	56	238.5	0.2				
Chile	3.7	38		1	5.7	365	1910			
Colombia	660	63	4	64	11					
Cuba	5		0.32	0.24		170		2		
Ecuador	795	31,800	1.3	244	9800					
Guatemala	13			1.3						
Peru	145	240	0.32	14	24				2	
Suriname	22			3.4						
Trinidad	510		16	34		10				
Venezuela	217,825	20,668	2000	45,310	2067	10				

Table 1. .....cont'd

	HEAVY OIL (x 10^6 m^3)					OIL SANDS (x 10^6 m^3) Page 2				
	Oil in Place		Reserves			Oil in Place		Reserves		
	Known	Speculative	Cumulative Production	Remaining	Speculative	Known	Speculative	Cumulative Production	Remaining	Speculative
EUROPE										
Albania	115			17		59			9	
Austria	1			0.02						
France	145		4	15		0.8				
Italy	1510		41	159					33.4	
Netherlands	98	34	20	13	5					
Norway	318			32						
North Sea	19			2						
Spain	72		12	8						
Sweden	0.8			0.02						
United Kingdom	8313			831						
W. Germany	370	87	7	18	23					
E. EUROPE										
Bulgaria	7			1						
Hungary	52		19	0.5						
Romania	375			56		4			0.6	
E. Europe	535		32	80	111					

Table 1. .....cont'd

	HEAVY OIL (x 10^6 m^3)					OIL SANDS (x 10^6 m^3) Page 3				
	Oil in Place		Reserves			Oil in Place		Reserves		
	Known	Speculative	Cumulative Production	Remaining	Speculative	Known	Speculative	Cumulative Production	Remaining	Speculative
USSR	(143,085)	(21,850)	(830)	1550 (17,300)	(3260)	*70,000 (124,359)			*12,700	*210,000
AFRICA										
Angola	47		6	1		1.6	874			
Cameroon	22		0.3	3						
Chad	541			108						
Congo		612			92	5				
Egypt	1840	267	48	175	105					
Gabon	2		0.8	0.3						
Madagascar	763			231		181	868		15	
Morocco	159			16						
Nigeria	684	22,200	32	121	4930	4930	1431		159	477
Senegal	100			10						
Zaire						33			3	

NOTE:

Figures in brackets are by Meyer and Mayerhoff
* Data from J. Yurko

Table 1. .....cont'd

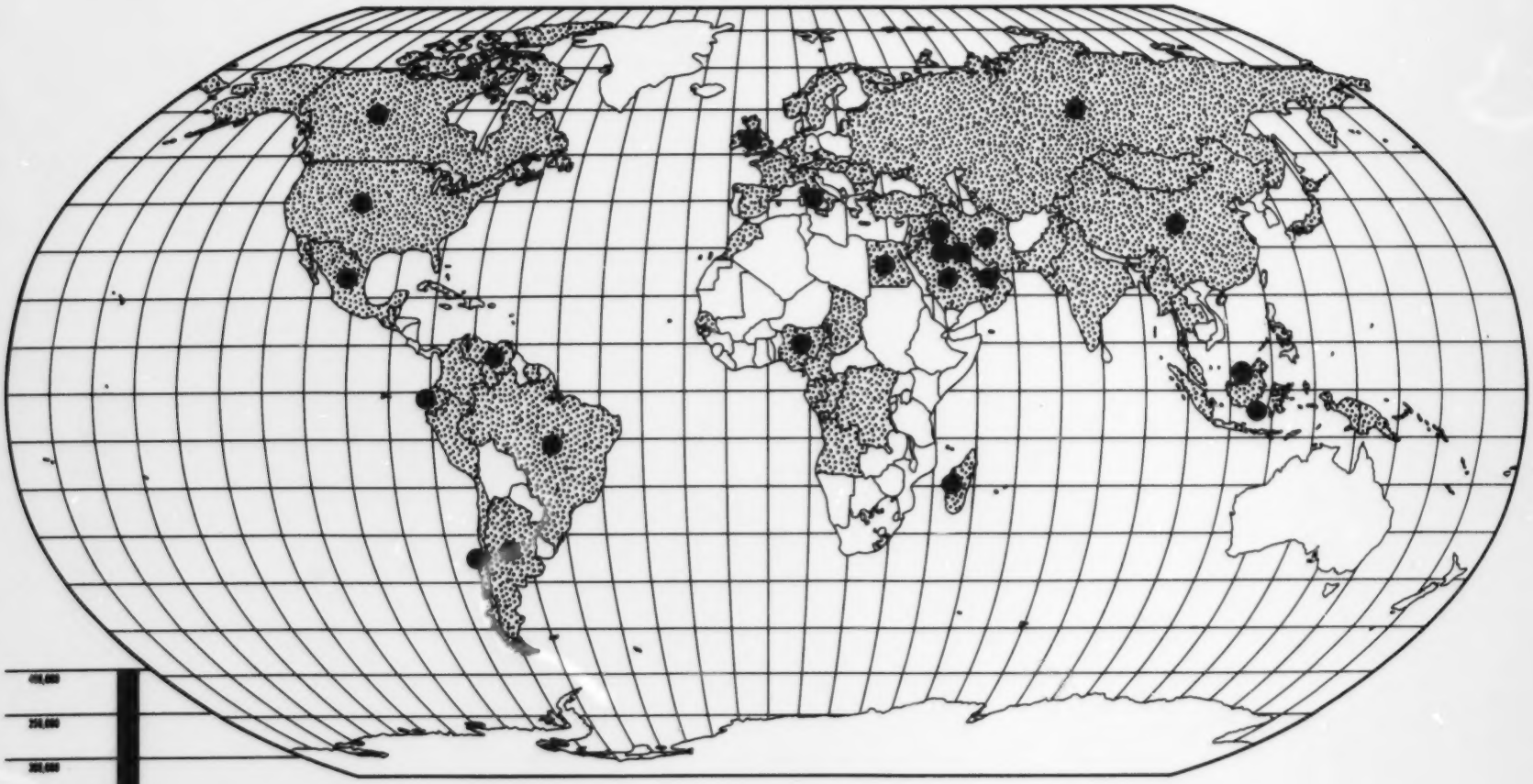
	HEAVY OIL (x 10^6 m^3)					OIL SANDS (x 10^6 m^3) Page 4				
	Oil in Place		Reserves			Oil in Place		Reserves		
	Known	Speculative	Cumulative Production	Remaining	Speculative	Known	Speculative	Cumulative Production	Remaining	Speculative
MIDDLE EAST										
Bahrain	66			1		51				
Iran	1436	604	48	270	207					
Iraq	9561	30,894	1701	1961	3180					
Kuwait	32,062	2390	2852	10,151	239					
Neutral Zone	2760	500	192	209	50					
Oman	644	143	10	64	16					
Qatar	382		95	80						
Saudi Arabia	3058	572	80	596	461					
Syria	445		21	95		0.2				
Turkey	668		16	48						
U.A.E.	636	640		64	64					
Jordan									16	16
ASIA/PACIFIC										
Brunei (& Malaysia)	1400	1680	159	207	252					
Burma	4.3	* 880	0.5	0.2	* 132					
China	4452		49	1081		1670				

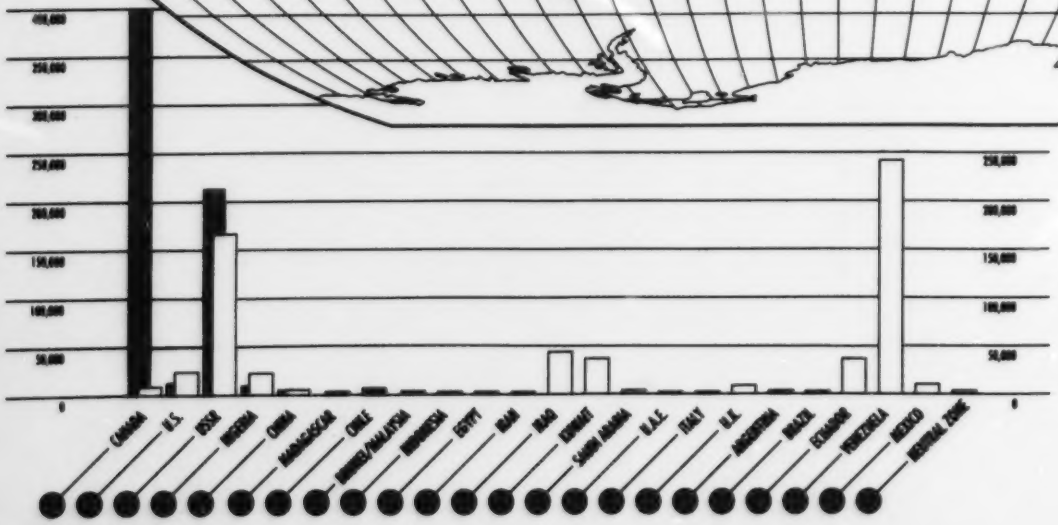
* Includes India and Pakistan

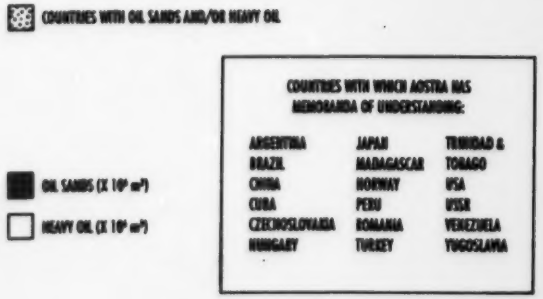
Table 1. .....cont'd

	HEAVY OIL (x 10^6 m^3)					OIL SANDS (x 10^6 m^3) Page 5				
	Oil in Place		Reserves			Oil in Place		Reserves		
	Known	Speculative	Cumulative Production	Remaining	Speculative	Known	Speculative	Cumulative Production	Remaining	Speculative
India	795	included with Burma	13	103	included with Burma					
Indonesia	1272	1073	188	64	111			3	85	
Japan	83		7	1						
Pakistan	21	with Burma	0.8	0.5	with Burma					
Thailand	80	795	0.2	8	80				1.4	
Mongolia	8			0.8		8				

Figure 1. Heavy oil and oil sands resources around the world



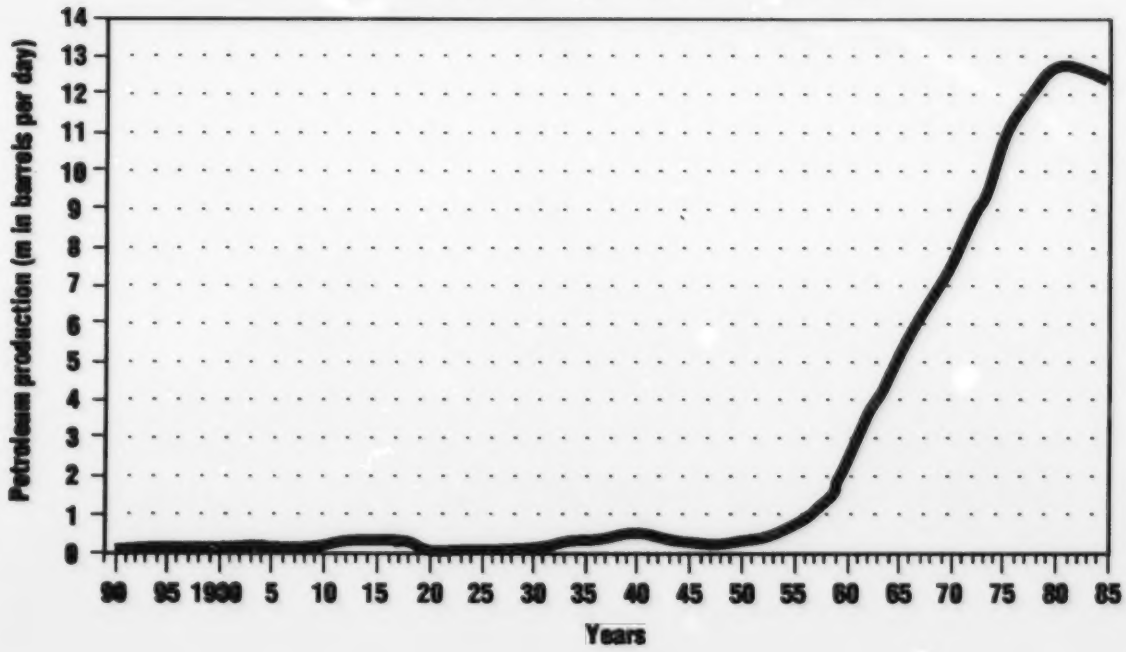




COUNTRIES WITH WHICH AOSTRA HAS MEMORANDA OF UNDERSTANDING:

ARGENTINA	JAPAN	TRINIDAD &
BRAZIL	MADAGASCAR	TOBAGO
CHINA	NORWAY	USA
CUBA	PERU	USSR
CZECHOSLOVAKIA	ROMANIA	VENEZUELA
HUNGARY	TURKEY	YUGOSLAVIA

Figure 2. Petroleum production in the USSR



Session 2

Paper no. 4

Dreding and Cold Water Extraction Process for Oilsands

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DREDGING AND COLD WATER EXTRACTION PROCESS FOR OILSANDS

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Abstract. The OSLO leases in the Athabasca area of N.E. Alberta contain significant mineable oil sands resources. Because these resources tend to be an expensive source of supply, new technology must be found that will allow commercial development and provide a hedge against crude price instability, inflation and exchange rates.

The OSLO joint venture (Alberta Oil Sands Equity, Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited, Gulf Canada Resources Limited, PanCanadian Petroleum Ltd. and PetroCanada Inc.) has been developing new technology for mining and extraction of oil sands since 1979, with Alberta Oil Sands Technology and Research Authority joining the program in 1987.

This paper describes the ongoing development of a year-round bitumen production technology employing a winterized dredge mining operation, hydrotransport by a slurry pipeline to a bitumen extraction plant employing the OSLO Cold Water Extraction (OCWE) process. Lower bitumen production costs are achieved through mechanical and thermal efficiencies which are reflected in lower capital and operating costs. The process produces tailings which may be able to form environmentally acceptable disposal areas. An 800 tonnes per hour pilot plant to prove commercial readiness is being designed for a 1991 or 1992 startup.

Although this technology will not likely be ready for implementation by the current OSLO commercial project design, it is aimed at the development of follow-up oil sands projects as the economic conditions permit.

INTRODUCTION

The OSLO joint venture of six companies of which Esso Resources Canada Limited (Esso) is Operator, holds six oil sands leases in the Athabasca area of Northeast Alberta (Figure 1). The joint venture was formed in 1981 to evaluate the leases and assess the technical and economic viability of developing the resources. In the process, a large, high grade surface mineable oil sand deposit was delineated in the northern portion of Lease 31 which has since become the focus for the OSLO Commercial Project, a 77,000 bbl/day synthetic crude oil project announced in September, 1988. This project currently in the definition stage, will utilize the best of proven technologies, maximizing economic and environmental benefits while minimizing risks.

In the early eighties, OSLO also initiated studies to develop new technology aimed at reducing overall bitumen production costs. It began by investigating dredge mining and hydraulic transport of ore as an alternative to dry mining and conveyor transportation. OSLO also embarked on an investigation of bitumen extraction techniques having a potential for lower energy consumption and environmentally acceptable tailings disposal.

In 1986, a new bitumen extraction process called OSLO Cold Water Extraction (OCWE) was conceived which in combination with dredge mining appeared to offer significant synergies. Alberta Oil Sands Technology and Research Authority has been participating with OSLO in the development of this technology since 1987. The dredge mining and OCWE system has since been tested in a series of increasingly larger laboratory tests and field pilots (up to 20 tonnes/hour). Encouraged by the results, it is being planned to test the system in a pilot scheduled to start in the early 1990's. Operations will be intermittent, as expected in a research pilot, with a planned capacity of 800 tonnes/hour. The pilot will further develop the technology and demonstrate the commercial readiness of a year-round dredge mining, OCWE and froth clean up operation by the mid 1990's.

DREDGE MINING OF OIL SANDS

Dredging is a recognized as a low cost earth moving/mining system. For many years it has been applied world-wide to mine various types of unconsolidated and consolidated minerals as well as to remove overburden. Oilsands are especially amenable to dredge mining, since they have virtually

no cementation and little shear strength. The occurrence of siltstone layers may cause some difficulty. The sandgrains in the oilsands fabric being water wet and unconsolidated, readily disintegrate in a water medium under agitation. The mechanical energy imparted by a dredge cutter head and later by friction in the discharge pipeline causes the disintegration of the ore and a significant liberation of bitumen. This combination presents an advantage over dry mining and conveyor transport system where horsepower is used solely for material handling. Ore disintegration and bitumen separation take place later in a tumbler with additional mechanical and thermal energy in the Clarke Hot Water Process (CHWE).

Leading dredge types considered for mining of oilsands include the basket cutter suction (figure 2) and the bucket wheel cutter suction (figure 3).Their comparative merits include:

- The basket cutter type is the most common in industry. Dredges with cutter power of 5000 KW have been successfully employed whereas the largest bucket wheel dredge has 500 KW wheel drive power.
- The spillage from the basket cutter is about 15-25% of the material cut and for the bucket wheel it is 5-10%. This is an important consideration as the spilled oilsands have to be rehandled.
- The bucket wheel normally produces higher slurry densities than the basket cutter dredge because the bucket wheel has less open area than a basket cutter head.
- The basket cutter cuts oilsands in an overcutting mode in one direction and in an undercutting mode in the return direction making it difficult to produce uniform slurry density in the pipeline. The bucket wheel, on the other hand, always operates in the undercutting mode providing uniform slurry density.
- Siltstone layers are easier to cut with a basket cutter mainly because higher horsepower can be provided. But if the siltstone is preblasted then this advantage diminishes.

These considerations, supplemented by experience with dry ore bucket wheel excavators tend to suggest that the bucket wheel dredge is preferred over the basket cutter dredge. However, clear-cut evidence of the superiority is not yet available.

HYDRAULIC PIPELINE TRANSPORTATION

Hydraulic pipeline transportation is an integral part of dredging. OSLO studies indicate that for a distance of more than two kilometers pipeline transportation costs for about 10 wt% solids slurry are equal to conveyor transportation costs for dry mining. However, slurry densities of 40-50 wt% solids have been achieved in a number of projects where the materials are free flowing into the dredge cutter head, such as loose sands. With these higher slurry densities, pipeline transport becomes very cost effective being 2/3 that of conveyor transport. For oilsands, it may be beneficial to preblast which will reduce both the tooth wear and give higher slurry densities.

OSLO carried out oilsands disintegration tests at Saskatchewan Research Council's pipeline test facility in 1987. About 100 tonnes of oilsands were trucked to the facility for use in a 175 m long, 250 mm diameter pipe loop. Slurry temperatures were maintained at 5°C and 15°C and slurry densities at 25 wt% and 50 wt% solids. At 5°C the oilsands completely disintegrated within about 10 minutes and at 15°C within about 5 minutes (see Table 1).

Results from the SRC tests indicated that a minimum of two kilometers of pipeline length is required to completely disintegrate the oilsands. This is based on a pipeline slurry velocity of about 4 metres per second required to maintain the solids in suspension.

SOME DREDGE RELATED ISSUES

Some of the traditional concerns surrounding mining by dredging include winter operations, handling of siltstones, rocks and oilsands grade control.

Winter Operations

A number of winter dredging operations have been carried out in Canada since the 1940's. These include:

- Steeprock Iron Mines – Atikokan Ontario,
- Caland Mine Project – Atikokan Ontario, and
- Eldorado Mine – Port Radium, Northwest Territories

Furthermore, a number of similar dredging operations are presently conducted in winter including:

- Eastmac Mine – Kirkland Lake
- LAC Minerals Mine – Kirkland Lake
- International Nickel Mine, Thompson, Manitoba

Steeprock mine was located 200 kms West of Atikokan, Ontario and has experienced winter temperatures of -50°F over prolonged periods of time. The materials dredged in this mine consisted of overburden made up of silts and clays. Two medium size cutter suction dredges with 750 mm discharge pipe, started operations in November 1950 working 24 hours per day year around, and completed the project in December 1954. About 50 million m3 of material was dredged. The dredges pumped 30-40,000 USGPM slurry at an average of 20 wt% solid content with a 5500 HP pump.

Similarly, the Caland Mine Project started in May,

1955 and completed in September 1960. At the time, the two largest dredges in the world (1075 mm pipe size) were used to mine similar materials as in Steep Rock Mines. Material was dredged from a depth of 120 metres and discharged through a 20 kilometre pipeline. Slurry density was 12-25 wt% solids and pumped at an equivalent rate of 3200 m^3 per hour solids. The main pump on this dredge was 10,000 HP. To keep the dredge area ice free in winter, icebreaking boats were used which broke the ice and corralled it to a drag-line which removed the ice pieces to a pile on the pond shore. The winter ice removal costs escalated to today's dollars would be about $0.10 / barrel of bitumen.

In the Eldorado Mine (N.W.T.), dredging was used to re-mine the uranium tailings for further extraction. The operation started in 1952 and continued to 1955. A suction dredge designed by Ellicott company was employed with a 100 mm diameter pipeline to transport slurry to the plant. The pipeline was laid on the ice in winter and rested on floating pontoons during the summer months. Winter operation was maintained by spraying 4°C mill water around the dredge. The spraying of water was sufficient to keep the dredge ice free in this most northern dredging operation.

The operation at Eastmaque Mine (Kirkland Lake, Ontario) involves mining gold tailings which were deposited in the lake in the 1930's and 1940's. The operation started in January 1988 and is continuing. Two 200 mm cutter suction dredges are employed which mine about 2200 tonnes of solids per day on a 2 - 12 hour shifts basis. Slurry density averages about 40-50% but a maximum of about 70% have been achieved. The pipeline diameter is 200 mm and about 2 kms long.

In winter the dredge pond is kept open by the movement of the dredge and an ice breaking boat used to circle the dredge. A 1.5 m^3 backhoe assists in removal of large ice pieces when necessary. The pipeline is laid on the pond floor in the winter and rests on the floating pontoons in the summer (Figure 4).

The operation at Lac Minerals Mine (Kirkland Lake Ontario) started in July 1988 with a 150 mm cutter suction dredge to mine the gold tailings. Dredge production is 700 tonnes/day solids working one 12 hour shift per day. The pipe diameter is 150 mm and the length is about 8 kms from the dredge to the plant. The slurry density varies from 20% to about 50% solids.

The dredge pond is kept open in winter by bubbling air through a 25 mm diameter pipe from a 600 cfm compressor installed onboard the dredge. The floating pipeline is also kept free of ice by the bubbling system. The air pipe hangs from the dredge about two meters below the hull of the dredge. This system has worked well for the winters of 1988 and 1989.

The International Nickel Mine (Thompson, Manitoba) has carried out three dredging operations each lasting about three years to remove overburden. Currently, dredging is carried out between March and December each year. The operation uses a cutter suction dredge which is of the same size as Caland. The pipe diameter is 1075 mm and length about 10 km. Winter operation includes the breaking of ice around the dredge and corralling the ice pieces in front of a dragline which removes ice on to a pile on the shore. Ice breaking is helped by blasting in advance of the ice breaking boats .

Studies by OSLO confirmed that in the absence of waste heat available from an upgrader, it would be cheaper to use mechanical means to break and remove the ice from the pond to keep the dredge operational in the winter.

The dredge operators have indicated no major operational delays or safety concerns due to the winter operation. The dredge relies on ultrasonic electrical instrumentation for positioning so operation is not impeded on the occasions when fog may set in. Obviously on these occasions, access boats are maneuvered more carefully to reach the dredge. The possibility of pipeline freeze-up is diminished by constantly circulating water through the pipe.

Silt Stone Layers

Silt stone layers up to about 0.3 m thick could be cut by the dredge and thicker layers would be blasted into small (1/3 pipe size diameter) pieces and then dredged. The cutter opening is such that any rock that passes into the cutter head would be carried to the screening unit. The rocks that are larger than the cutter opening, will not be dredged but will be removed to shore by a backhoe mounted on a floating barge.

Grade Control

In a dredging operation, the pit face would be underwater and visual control is impossible. Oilsands grade control would be provided mainly by close pre-drilling for better advanced definition of the ore body and by a detailed mine plan. In addition, a three phase analyser (bitumen, water, solids) is being developed by OSLO in order to guide plant operation.

THE OCWE PROCESS

OCWE is a patented cold water bitumen extraction process in which liberated bitumen particles with the assistance of chemicals attach to air bubbles and float as bitumen froth product in a flotation cell. The process has been tested at

temperatures above 3°C. Below 15°C, the liberated bitumen particles exhibit very little affinity towards air bubbles for flotation. This affinity is improved by the addition of flotation chemicals. The chemicals addition rates can be decreased as the temperature increases above 15°C. A similar effect can be achieved by optimizing mechanical shear input in obtaining bitumen liberation. Thus, it is the cumulative effects of temperature, mechanical energy and chemical addition that contribute to high bitumen recovery (90% plus) in the OCWE process, as shown in Figure 8. In contrast, the Clarke Hot Water Process utilizes the density differential between bitumen and water for effective separation of bitumen from water and solids.

The OCWE process has been progressively scaled up from 500 gram batch tests in 1986/87 to 2 to 3 tonnes batch tests in 1988 and then to 15 tonnes/hour pilot tests (6 hours duration) in 1989 as shown in Figure 5. The bitumen recoveries, froth product quality and tailings properties remained relatively the same for all levels of testing to date. A brief description of the pilot plant and the results obtained are described in the following section.

The current OCWE pilot site is located about 10 kms north of the city of Fort McMurray on OSLO Lease 41 (Figure 6) and tests were carried out in two summers (1988 and 1989). There are three distinct operations involved in this pilot set-up, which are as follows:

- feed slurry preparation to liberate bitumen from oilsand fabric (dredge mining)
- separation of bitumen as froth product (extraction)
- settling of tailing solids and recycle of process waste

The layout of the pilot is shown in Figure 7. The dredge mining action was simulated by an experimental 1.0 metre diameter dual bucket wheel mounted on a backhoe to allow raising and lowering of the bucket wheel as well as a means of advancing it along the mining pit. A rectangular mining pit of about 50 metres long, 5 metres wide and 2 metres deep was excavated. This mining pit provided both in-situ oilsands for dredging and as a reservoir for placing various grades of oilsand feeds obtained from other sites. In the latter case, the oilsand feed was placed in the pit and covered with water to about 0.75 metre above the oilsand feed and dredged by the experimental wheel. During the dredging action, oilsand feed disintegration starts due to the cutting action of the dredge wheel. The process parameters that affect the cutting efficiency are: geometry of the wheel, energy input, water temperature and nature of the oilsand feed. The partially disintegrated oilsand-water slurry was then pumped to the extraction vessel via a 75mm diameter steel pipe about 500 metres long. The oilsand feed continues to disintegrate due to pumping and pipeline transportation actions. The length of the pipe and the pumping energy are varied to obtain the complete disintegration of oilsand feed to liberate the bitumen from solids and water.

Proprietary chemicals and air were added to the bitumen-water-solids slurry prior to discharging into the extraction vessel for bitumen separation. The amount of chemicals and air added vary depending on the feed bitumen content and slurry temperature. In addition to the above process parameters, the flotation cell configuration impacts on the efficiency of bitumen separation. The geometry of the flotation cell should promote the fast settling of solids and removal of such settled solids at a rate that does not impede the rising bitumen-air froth. With such a view, two types of vessels, a trough type (horizontal) and a circular (vertical vessel) were tested.

The spent solids (tailings) from the extraction vessel were pumped to the tailings pond where coarse solids (sands) settled out and the rest of the solids flowed to fines ponds. Two fines ponds were used for fines settlement allowing 48 hours of settling time prior to recycling of process water.

The 1989 pilot operations were carried out between July and September. About 1500 tonnes of oilsand was processed through the pilot plant during this period at prevailing ambient temperatures (3°C to 25°C). Both low grade (6% bitumen, 40% fines) and high grade (12% bitumen, 10% fines) oilsand feeds were processed. High bitumen recoveries were obtained (90% plus) in these tests and as well established the boundary conditions for various process parameters. The air addition rate, the air bubble size distribution and the water to oilsand ratio were observed to impact on bitumen recovery (see Figure 9).

Synergy of the OCWE Process with Dredging

The dredge mining and the OCWE process are synergetic for the following reasons:

- The sand grains in the oilsands fabric are water wet so they disintegrate readily in the water medium in which the dredge operates and pipeline transportation takes place. The oilsands disintegration starts at the dredge head and continues in the pipeline. Thus, the energy spent in cutting and transportation is utilized for bitumen liberation. The oilsand disintegration in dry mining is achieved in a tumbler with the addition of heat which can be eliminated in a dredging and OCWE type of operation.
- The oilsand is always under water, preventing freeze up in winter, thus making it easier for the dredge cutting operations.
- In addition, weathering and ageing of oilsand does not take place, which may reduce the bitumen extraction recoveries
- The OCWE process can handle a wide range of

water to oilsand ratios in feed slurry as anticipated in typical dredge mining.

These synergies between the dredge mining and the OCWE process offer potential for a substantial reduction in bitumen separation costs.

BITUMEN FROTH TREATMENT

properties of the froth obtained in the OCWE process differ from that obtained in the Clarke Hot Water Extraction (CHWE) process as shown below:

Process	Bitumen (wt%)	Water (wt%)	Solids (wt%)	Temp. (°C)
OCWE	60	20	20	Ambient
CHWE	60	30	10	80

Two novel separation processes are being developed to clean up the OCWE froth and to obtain bitumen product containing less than 2 wt% solids and water. The two processes include a high temperature proce[illegible]nd a low temperature process. In both techn[illegible], diluent is required for separation. Th[illegible]uct is sent through a diluent recovery step w[illegible]e the diluent is recovered for reuse. A 1L/hour laboratory pilot has indicated promising results.

TAILINGS MANAGEMENT

The sedimentation and consolidation properties of the OCWE tailings are similar to the original materials. The chemicals used in the OCWE process do not seem to give rise to sludge formation on a scale seen at existing oil sands plants (so called caustic sludge). These characteristics have been confirmed in the laboratory using standard cylinder and rectangular tanks tests.

The laboratory tests on the OCWE fines (less that 22 microns) indicated the following:

- For the same solids content, the OCWE fines sedimentation time is an order of magnitude less (weeks) than that of caustic treated fines (years).
- The OCWE fines consolidate to about 30% solids density in about 1 to 3 months whereas caustic treated fines take years to reach this density.
- The cylinder and tank tests indicate that OCWE fines consolidated to about 25 wt% solids content, and would support a surcharge layer of sand with minor penetration of sand into the fines layer. A 30 wt% solids fines layer supported a surcharge layer without any penetration of the fines layer (Figure 10). It is expected that further consolidation could occur due to compression through layering.

In summary, the tailings and fines studies carried out on small scale OCWE tailings tests indicate that OCWE fines settle rapidly in days, to free up substantial amounts of water for reuse. Sediments compact to 30 wt% density in 1 to 3 months. The density of the 30 wt% solids have sufficient strength to support the surcharge layer of sands. This offers possibilities of containing fines within the tailings mass in layers, thereby creating reclaimable tailings at the end of the project which is environmentally very attractive.

The following solids disposal concepts are possible which take advantage of the above noted characteristics:

1) Tailings pond dykes constructed similar to the present commercial practice and containing fines in one thick layer in the centre. The whole centre layer would then be capped with dry sand. Vertical drain towers for water release will be required for this approach (figure 11a).
2) Tailings pond dykes similar to (1), but the fines alternatively layered in the pond centre with the coarse sand (figure 11b), and
3) A thickened discharge layer method can be used to capture additional fines in the dykes and the balance in the pond would be covered as in 1 and 2 (Figure 11c)

AREAS FOR FURTHER TECHNOLOGY DEVELOPMENT

The following issues will be addressed in the Minimum Size Demonstration Pilot:

Dredging

- Dredge cutter head designs will be tested to achieve maximum slurry density and consistency.
- Winter dredging must be carried out to better define potential problems.

Pipeline Transportation

- Oilsands disintegration as a function of pipeline size requires further study.
- Air/slurry pipeline flow conditions will be studied to achieve optimum mixing.
- Pipe wear will be determined for the conditions studied.

OCWE Process

- Optimum separation vessel size and shape will be defined
- Cold froth handling characteristics need evaluation.
- Froth quality will be optimized with separation vessel parameters.

Tailings Fines

- Several promising tailings systems will be tested and evaluated to ultimately confirm the commercial viability of producing reclaimable tailings.

Froth Treatment Process

- Several OCWE froth clean up processes will be tested.

MINIMUM SIZE DEMONSTRATION PILOT (MSDP)

The dredging/OCWE technology has been tested in a 15 tonnes/hour integrated pilot plant. In order to scale up to enable a commercial sized plant (about 4000 tonnes per hour oil sand), additional testing must be carried out at a larger scale to better establish the design criteria. A survey of the dredging and the mining industry established the following sizes as reasonable for scale up. The basis of the MSDP design is:

	Minimum Size Required for Scale-Up	Equivalent Tonnes/hour
Dredge	Medium Size (400 mm pipe)	800
Cutting Power	700 HP	800
Transportation	200 mm-250 mm pipe diameter	200
OCWE Process	15 tonnes/hour	15

The above criteria indicate that the dredge size would establish the size of a demonstration pilot. A 400 mm size dredge corresponds to about 800 tonnes/hour oilsand production. Therefore, to prove commercial readiness, current plans include the installation and testing of an 800 tonnes/hour demonstration pilot capable of operating in winter.

The pilot will include a medium size dredge (700 HP, 400 mm pipe), screening unit, two stage extraction vessels and tailings ponds (Figure 12). The pilot layout and equipment configuration will be based on the Lease 41 experience complete with a comprehensive tailing management program.

The pilot plant will be located on the Syncrude lease and the produced froth would be sent to Syncrude for processing. A low temperature froth treatment process will be lab tested. The dredging/OCWE demonstration pilot will operate in the early 1990's, with some phases such as tailings management continuing to the mid 1990's. Confirmation of design assumptions would indicate a promising new technology is available.

Commercialization Potential

Realizing the full commercial potential of new technology is always a dangerous game, especially if the developers are premature in its development.

For example, the RAND Corporation in a study entitled "Understanding the Outcomes of Megaprojects: A Quantitative Analysis of Very Large Civilian Projects" had some reservations about the premature commercial use of new technology. For example,

"The use of new technology is the only factor that is associated with bad results in all three dimensions: cost growth, schedule slippage and performance shortfalls."

"... megaprojects are simply inappropriate vehicles for experimentation."

These realistic concerns, magnified by the large sums of capital at risk, dictate a prudent, paced research program that clearly demonstrates commercial readiness both from an incentive and risk perspective.

If the technical, environmental and economic success factors laid out for the 800 tph pilot are met, incorporation of the technology could occur as we approach 2001, marking a new odyssey in oilsands development.

CONCLUSIONS

The following conclusions can be drawn from the dredging/OCWE process technology development program to date:

- New technology is required to reduce cost of synthetic crude oil production. Dredging/OCWE technology appears to offer a significant breakthrough in reducing capital and operating costs.
- Dredge mining of oil sands must be field tested under summer and winter conditions to establish cutting capacity and winter operability.
- The OCWE process has been demonstrated in successive steps from 500 gms batch tests to a 15 tonnes per hour pilot. Further scale up tests will be required to establish a commercial plant design basis.
- The OCWE process tailings have characteristics that hold out the promise that a reclaimable tailings disposal system can ultimately be developed.
- A large pilot to demonstrate integrated dredging, OCWE and tailings disposal technology and prove winter operability will be built on the Syncrude Canada lease. This facility will establish the design basis for the design of commercial facilities.
- Successful operation of the dredging/OCWE demonstration pilot would provide opportunities for commercializing other leases in the Athabasca area.

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Table 1

SRC Pipeline Oilsands Disintegration Test

Test	Solids	Temp	Disintegration (%) 1 min	5 min	10 min
1	50%	5°	41	90	98
2	50%	13°	65	99	100
3	25%	5°	48	94	99
4	50%	16°	53	96	100
1&3	-	5°	45	93	99
2&4	-	15°	60	98	100

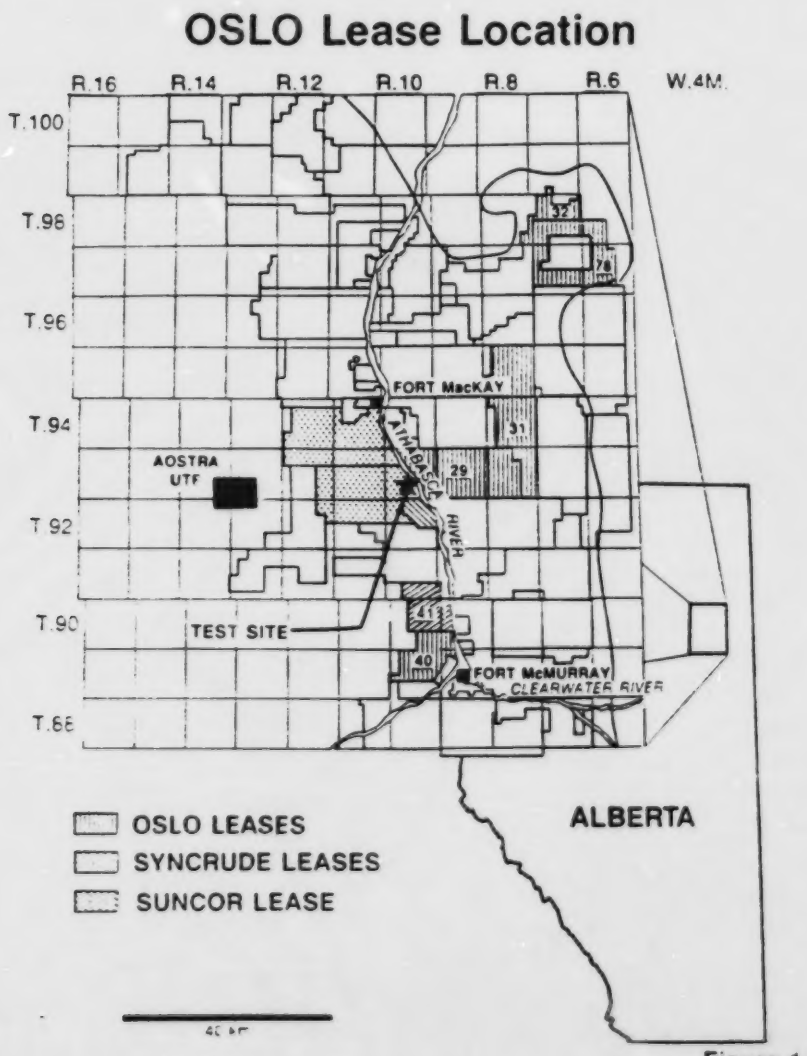

Figure 1

BASKET CUTTER SUCTION DREDGE

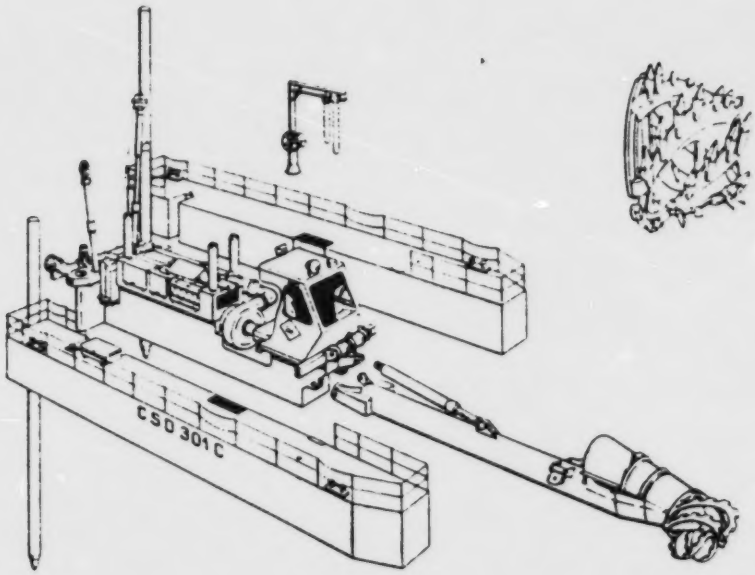

Figure 2

BUCKETWHEEL SUCTION DREDGE

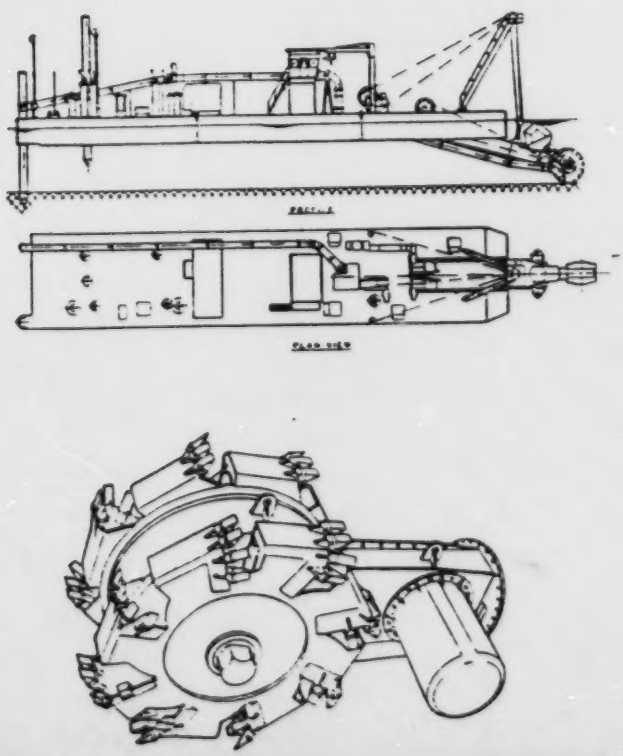

Figure 3

Dredge "Michelle" shore connections

Eastmaque Gold Mines Ltd. Dredge "Jewell"

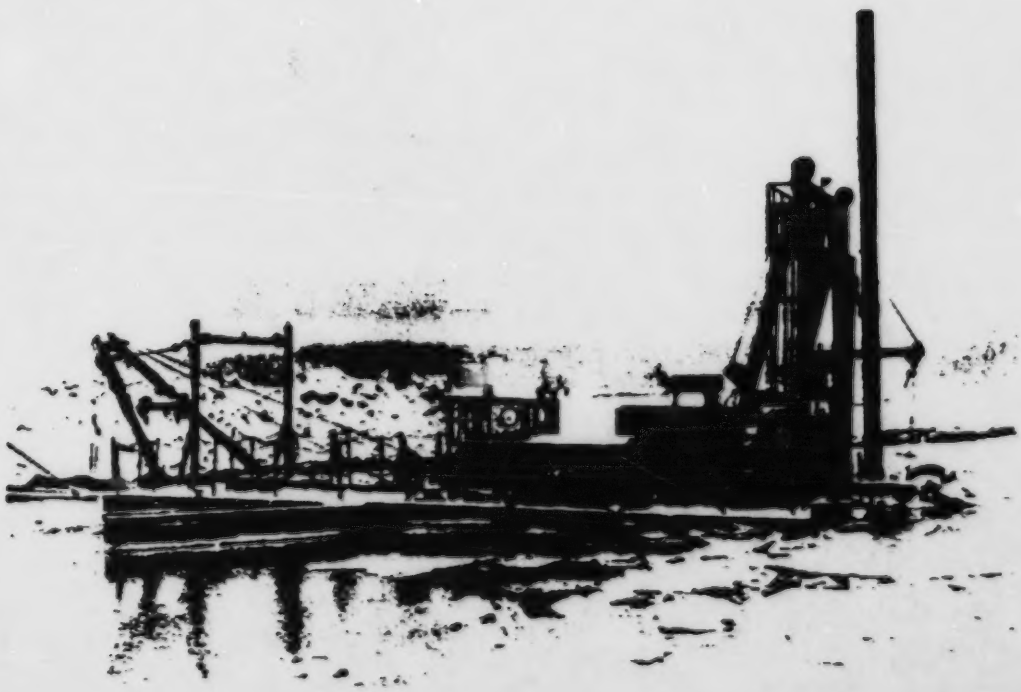

FIGURE 4

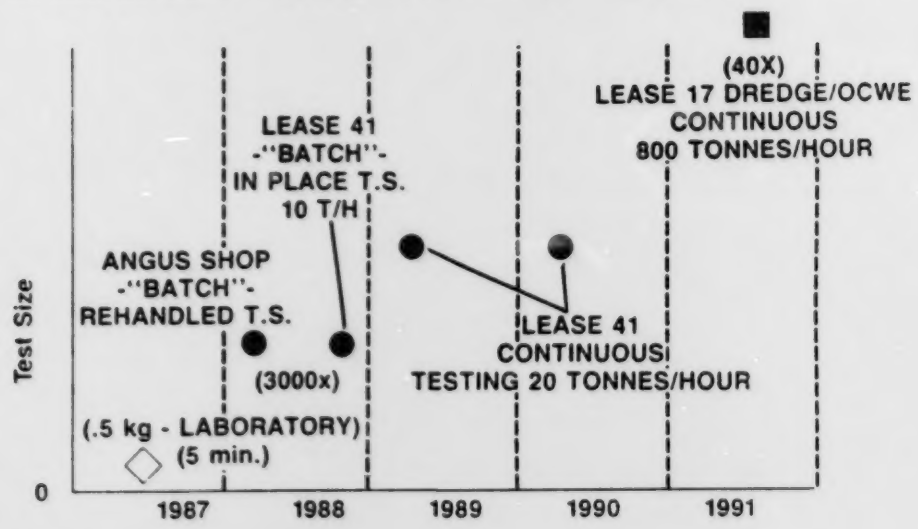
DREDGING / OCWE SCALE - UP STEPS
Test Size
0
1987
1988
1989
1990
1991
(40X)
LEASE 17 DREDGE/OCWE
CONTINUOUS
800 TONNES/HOUR
LEASE 41
-"BATCH"-
IN PLACE T.S.
10 T/H
ANGUS SHOP
-"BATCH"-
REHANDLED T.S.
(3000x)
LEASE 41
CONTINUOUS
TESTING 20 TONNES/HOUR
(.5 kg - LABORATORY)
(5 min.)

Figure 5

FIGURE 6

1989 LEASE 41 PILOT SCHEMATIC

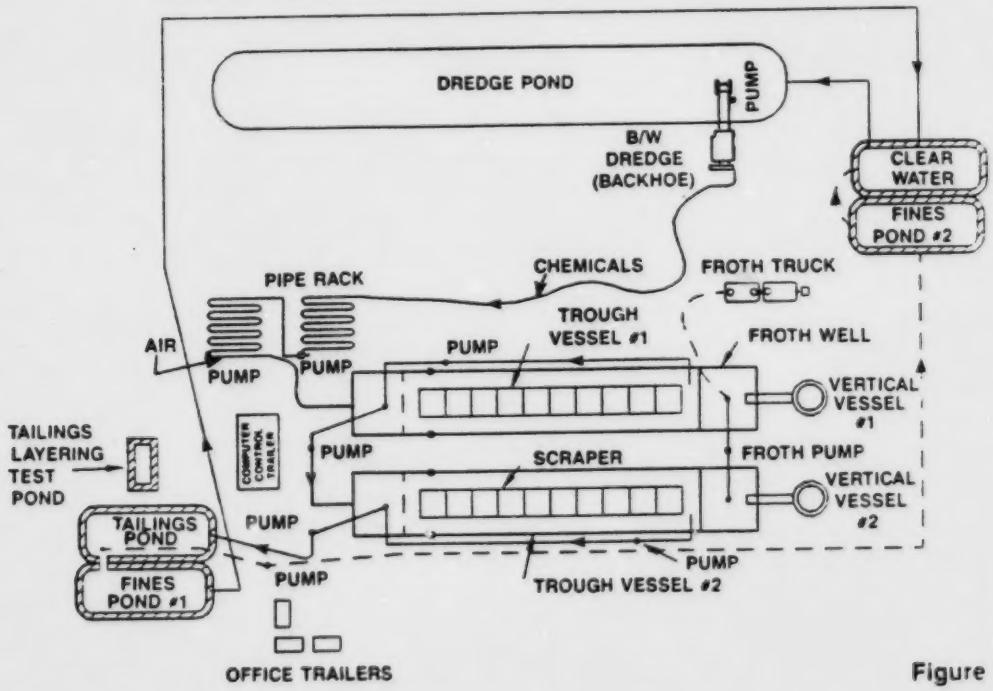

Figure 7

SUMMARY OF RESULTS OF OCWE FLOTATION TESTS AND COMPARISON WITH HOT WATER EXTRACTION RESULTS

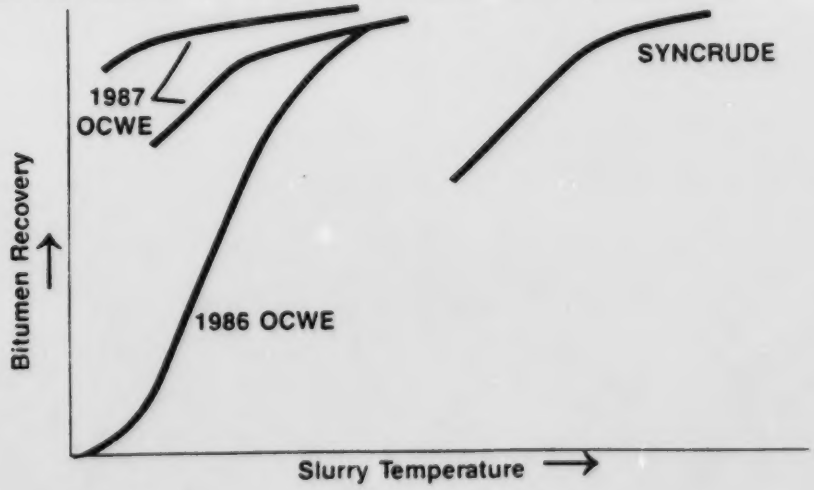

Figure 8

SUMMARY OF RESULTS OF OCWE PILOT TESTS FOR LOW AND HIGH GRADE OILSAND FEEDS

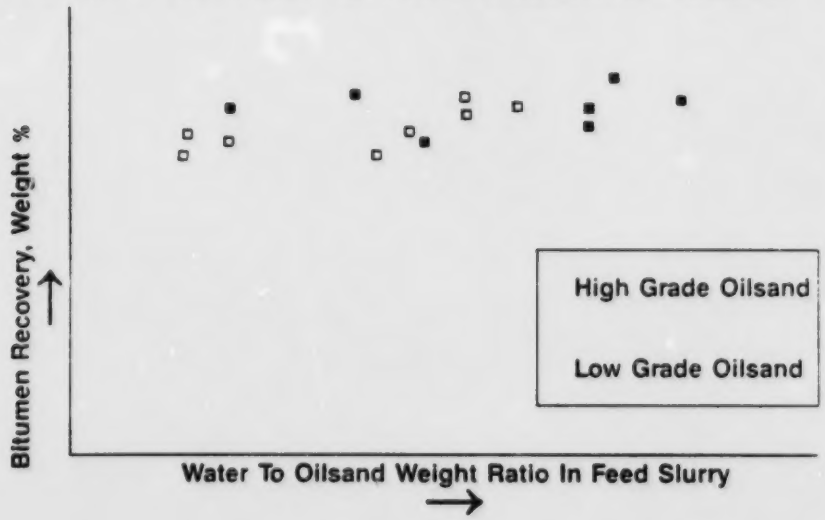

Figure 9

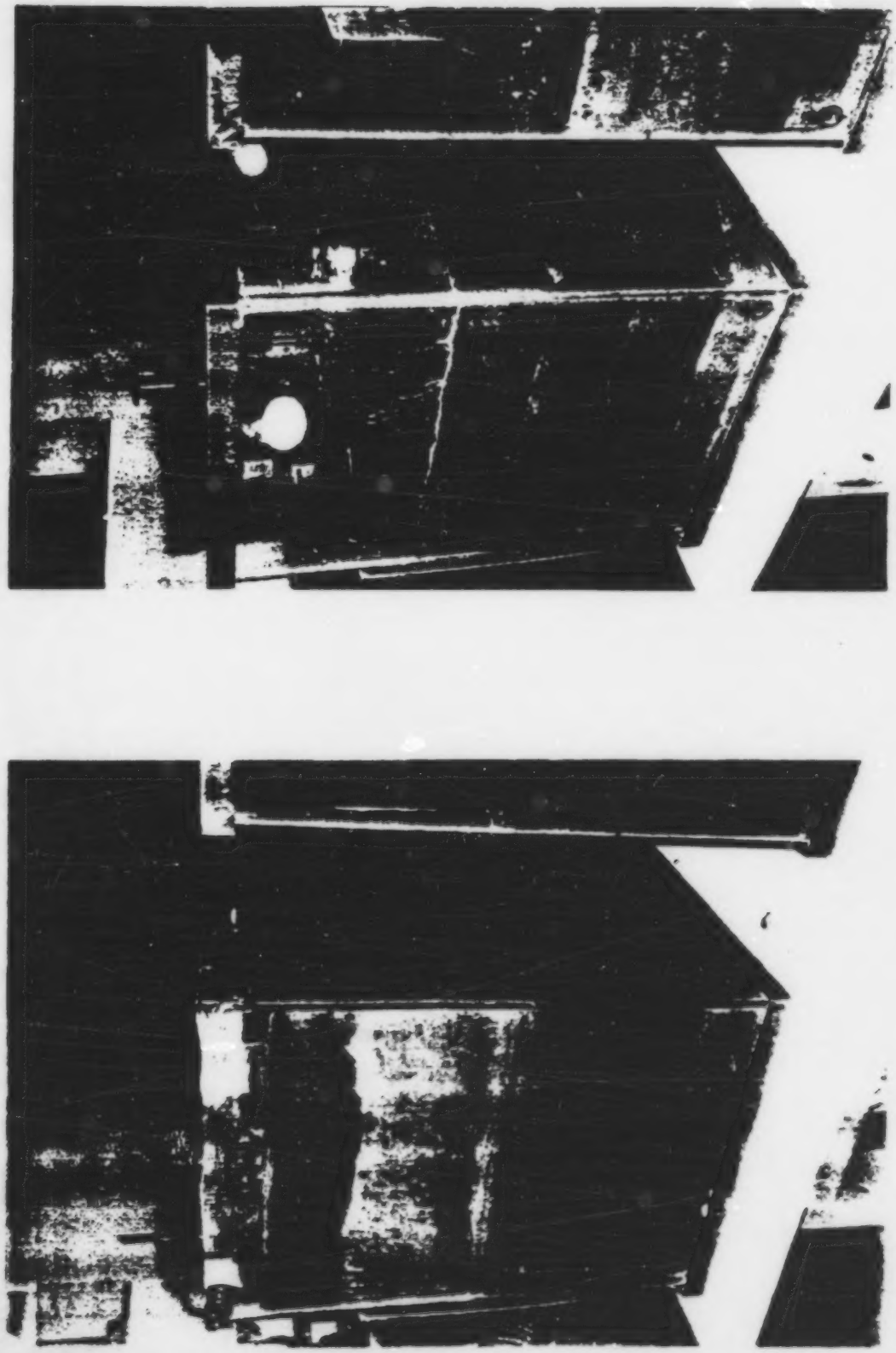

FIGURE 10

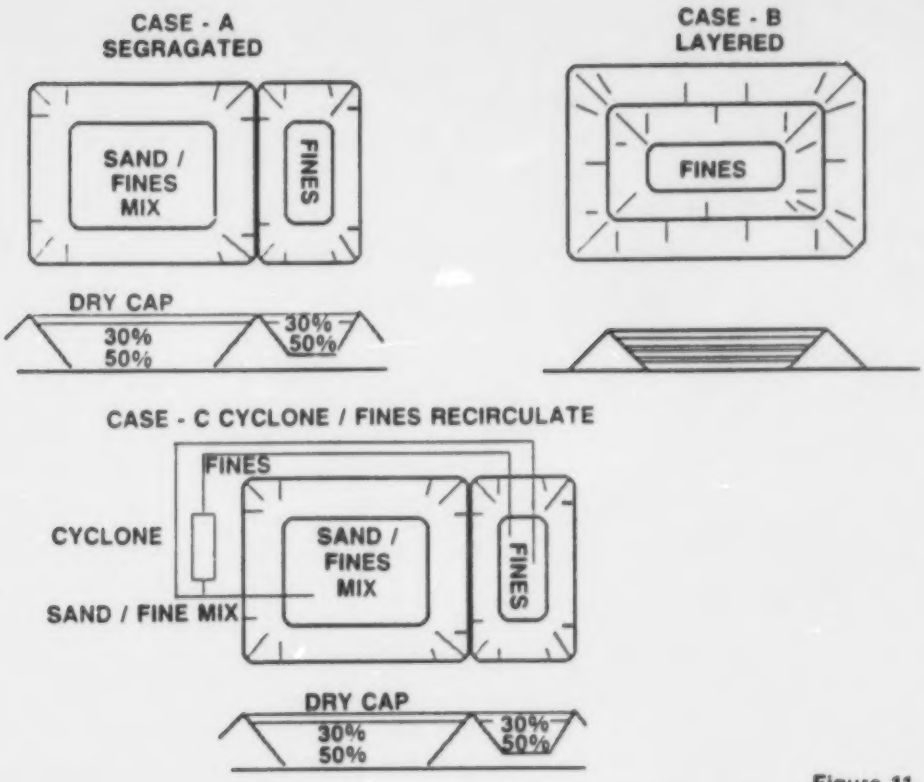

Figure 11

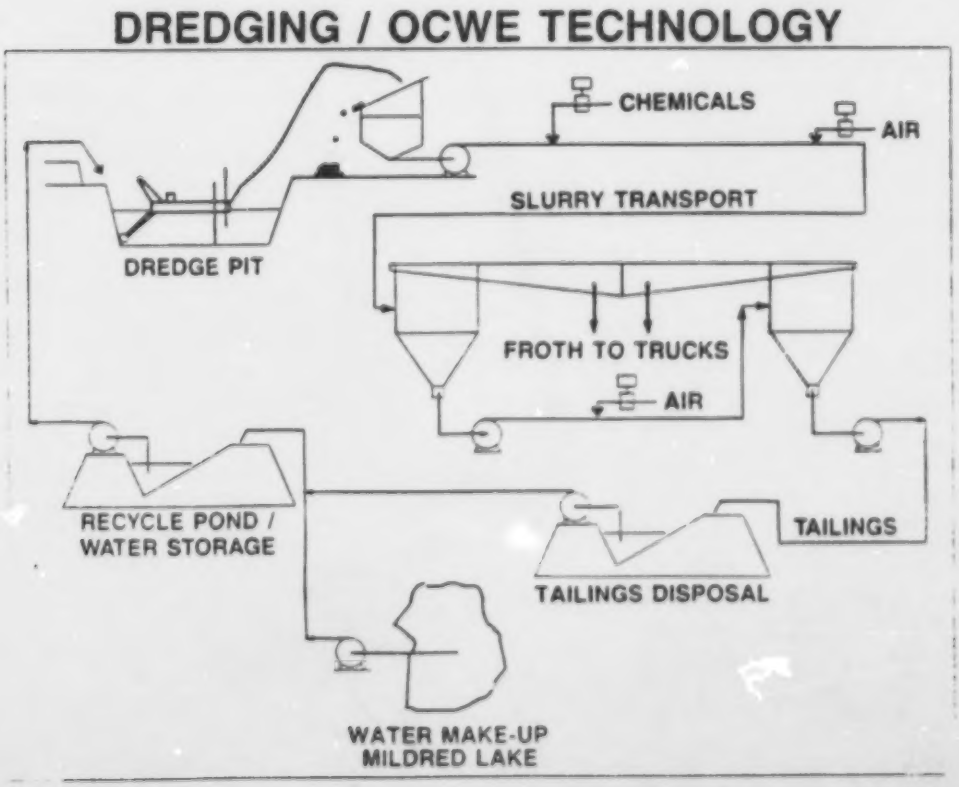

Figure 12

The SESA Process For The Recovery Of Bitumen From Mined Oil Sands

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NRCC #31244

Summary. The SESA process for recovering bitumen from mined oil sand was devised by the National Research Council and is under licence to Terra Energy Ltd. The process employs a naphtha solvent under controlled conditions, where the fines and other solids are agglomerated into free-settling spherical nodules. Under the joint sponsorship of AOSTRA and NRC a comparative engineering and economic study of commercially sized Hot Water- and SESA-based plant complexes has been completed. The study shows substantial recovery, environmental and other benefits of the SESA Process, together with economic advantages, assuming that any future Hot Water oil sands plant would be required to accept stringent environmental standards.

Introduction

The surface mineable oil sands of the Athabasca region of Alberta represent a petroleum resource five times as large as the remaining conventional reserves in the rest of Canada. Two integrated mining-extraction plants, Suncor and Syncrude, have been producing high quality synthetic crude oil (SCO) from this resource since 1967 and 1978 respectively. Total production from these plants now amounts to about 200,000 bbl/d of SCO, or approximately 15% of current Canadian consumption. The importance of this resource to future national energy self-sufficiency cannot be overemphasized.

At the present time the existing mining-extraction plants use versions of the Hot Water (HW) process, originally developed in the 1920's by Dr. K.A. Clark of the Alberta Research Council. Briefly this process comprises dispersing mined oil sands ore in hot water and then gravity separating a bituminous froth from the coarse sand tailings. A middlings stream of suspended fine solids and clays is treated separately, by flotation, to scavenge any entrapped bitumen. The combined froths are dissolved in naphtha and centrifuged to remove solids and water. After removal of naphtha the bitumen is upgraded to SCO.

While the HW process has been technically and economically successful, the basic requirement for fine dispersion of the ore in alkaline, hot water has resulted in massive aqueous tailings production. The coarse sand fraction settles readily and can be used to build containment dykes and beaches. However, the fines and associated residual hydrocarbons form a stable, non-compacting sludge which must be stored in large tailings ponds. At the present time there is no environmentally or economically acceptable means of treating the existing tailings ponds in such a way as to allow satisfactory land restoration.

The perceived need for an improved method for the separation of bitumen from oil sands is demonstrated by the fact that over sixty alternative processes have been patented (1). In particular, anhydrous processes have received much attention owing to the elimination of aqueous tailings by this approach; solvent extraction methods fit into this category. Solvent extraction is also attractive because of the potentially high recovery of oil from all grades of ore, owing to the ready solubility of bitumen in many solvents. However, the presence of fines in oil sands ore can inhibit the separation of the produced bitumen solutions from the residual solids, resulting in processing difficulties.

In order to overcome this solids-liquid separation problem the SESA process combines solvent extraction with another technique called spherical agglomeration. Spherical agglomeration (SA) is a process in which liquid-suspended fine particles can be formed into larger, dense agglomerates by means of suitable agitation in the presence of a second liquid, which must be immiscible with the suspending medium. The naturally water wet condition of the particles comprising oil sands make this system an ideal candidate for application of SA technology (2). In this case bitumen is dissolved in a hydrocarbon solvent which then acts as the solids suspending medium. As the solids are already water wet controlled, additional amounts of water can be used as the immiscible second liquid to bind the solids into agglomerates. Agitation by tumbling is the driving force for solids agglomeration. Phase separation results in a clean bitumen-solution and a solids tailings with a relatively low bitumen and solvent content.

Background

The spherical agglomeration process (now known generically as liquid phase agglomeration) had its origins in some fundamental work on particle-particle interactions, carried out by Dr. Ira Puddington's Colloid Group at NRC in the early 1960's. Initial emphasis for process application was on the formation of spherical articles (hence the name spherical agglomeration) from metal and ceramic powders. These spherical articles, after sintering, required much less finishing than equivalent products produced by conventional powder pressing techniques.

It was soon realised that the selective wetting characteristics, inherent to the process, made it useful for mineral beneficiation applications. Results with finely disseminated ores were generally superior to those obtained by flotation processes. Recently, an application of the process for recovery of gold from low grade ores or tailings has received serious consideration.

One of the first minerals to be treated by the process was oil sands; an example with this material was given in one of the first patents (3) covering mineral separations. In this early work oil sands was dispersed in cold water and the bitumen itself agglomerated. Further development resulted in a process for cold water bitumen separation, using a continuous screw device. This approach was considered for recovery of bitumen from tailings pond sludge by Sun Oil, the parent company of GCOS, or Suncor as it is now.

The GCOS (Suncor) plant commenced operations in 1967 and by 1973 it was apparent that build-up of sludge in the tailings pond was occurring at a greater than expected rate. This was largely attributed to the processing of lower grade ores from the upper bench of the mine. As a result of an approach by Suncor to NRC to discuss this problem the SESA concept was proposed, with the aim of treating low grade ore only. The process utilised agglomeration to mechanically desolventise the extracted oil sands solids. A minimum of 15 w/w% fines in the oil sands ore was required to provide sufficient agglomerate strength to allow the formation of large spheres (about 10 mm) which gave optimum solvent separation through a layering-compaction mechanism (5).

Terra Energy Ltd. (TEL) obtained the licence for this technology in 1974 and subsequently contracted MHO International to carry out a technical and economic evaluation (6,7). It was apparent from these early studies that solvent recovery and the ability to treat all grades of oil sands were important aspects for successful application of the process.

In 1983-84, Petro-Canada undertook an evaluation of a number of different, generic bitumen extraction schemes. The SESA process was selected for study by virtue of its being a leading example of the solvent extraction type. Process modifications were made so that all grades of oil sands could be treated. In the scheme finally adopted agglomeration was restricted to binding together the fines and coarser particles, present in all feed grades, to form small aggregates (1 mm). These aggregates showed the same rapid solid-liquid separation characteristics as the coarse sand which is the predominant particulate species in high grade ores. A successful pilot plant testing programme was carried out at the Process Research Laboratory in Calgary (8). The continuous pilot unit encompassed all process operations, including solvent recovery by steam stripping. This process did not, however, produce a dry tailings. During this same period Cambrian Engineering carried out studies on the kinetics of dry steam stripping of residual solvent from tailings and investigated a novel energy recuperation scheme (9,10).

Process Details

A simplified flow diagram for the process treated in the Kilborn study is shown on Figure 1. The feed system transports ore into the extraction/-agglomeration unit, the heart of the process, where the extracting solvent and water are contacted with the ore. The unit is a tumbler device rotating at low speed (about 10-20% of the critical rpm). Mixing of the ore, solvent and water is assisted by a charge of steel rods. The extraction solvent is a recycled dilute bitumen solution from a later stage of the process; the presence of bitumen greatly improves the dissolving power of naphtha, which is the primary solvent. Water, in controlled amounts, can be added as liquid, or steam if additional energy is required to thaw frozen feed. The process is operated at 50°C, no additives, such as alkali, are required.

Bitumen dissolution and sand agglomeration occur concurrently in the tumbler. Water (or steam) added to the system is preferentially adsorbed by the ore grains, displacing bitumen and solvent from their surfaces in the process. In the presence of appropriate amounts of water the solid particles adhere to each other, through the capillary action of the surface water films, to form multi-particle agglomerates from which the bulk of the bitumen and solvent is excluded. Agglomeration is very rapid and some undissolved bitumen can be occluded within the growing agglomerates. The tumbling charge of steel rods in the vessel continuously break down agglomerates as they form, thereby re-exposing any trapped bitumen to the extracting solvent and allowing more opportunity for bitumen to be dissolved. This continuous formation and destruction of agglomerates also assists in controlling agglomerate size within the most desirable range (0.5-1.5 mm). Control of particle size is the key factor for the successful operation of the next process stage, which is separation of the agglomerated, extracted solids from the rich bitumen solution.

Vacuum filtration has been selected as the most appropriate solids-liquid separation technique for this process. A pan filter offers the simplest, most operable device for this step. The horizontal, segmented, continuously rotating filter allows multistage, countercurrent washing of the solids but with all filtrate fractions being kept separate. Pulp consistency in the agglomerator unit is high enough (~ 60 w/w% solids) so that the discharge can be loaded directly to the filter. The first filter segment is a drain step which allows separation of the product stream, containing about 50 w/w% bitumen, from the solids. As the pan rotates to the different segments the retained solids are washed counter-currently with progressively cleaner solvent to remove entrained bitumen solution. After a final step to drain the bulk of the liquor from the last, clean solvent wash the solids are automatically discharged by an auger device. The filtrate from the initial wash step, (containing about 35 w/w% bitumen) is recycled back to the primary extraction unit.

The product stream is normally low in solids and water, however, two stages of inclined plate settlers are included in the process scheme to handle problems resulting from process upsets. Table I illustrates the bitumen quality produced by the SESA process with different grades of oil sands and solvent types. These results were obtained without any additional treatment of the filtrate product. For comparison purposes results for bitumen product from the HW process are also included. In the latter case the product has undergone filtration and two stages of centrifugation.

The filtered, washed solids from the SESA process contain 4-6 w/w% solvent and are virtually free of bitumen. Most of the residual solvent has been displaced from the internal porosity of the agglomerates and is only weakly held in the larger pores of the filter cake. An important aspect of the process is the economical recovery of this solvent. The means selected to accomplish this goal is a rotating, tubular dryer, utilising both indirect heating and internal steam stripping. The unit has a novel arrangement for vapour take-off and steam addition in order to obtain maximum utilisation of the energy required for drying and to reduce the amount of water recovered with the solvent. Although the demonstration plant will not incorporate any energy recuperation schemes the process will be monitored to obtain the information necessary to optimise design for energy integration in a commercial plant.

A large number of solvent recovery tests have been carried out in small scale batch and continuous modes, using different types of equipment . It has been clearly demonstrated that virtually complete (<100 ppm residue) solvent recovery can be achieved provided that the naphtha solvent has a final boiling point of less than 180°C; this is also an important factor in the concomitant removal of water along with solvent from the agglomerates. The latter result is undesirable from an energy conservation point of view. Analysis of the drying data and energy requirements indicate that it is not economically feasible to reduce the solvent content of the tailings below 0.25 w/w%. Table II compares the tailings composition of the HW and SESA processes for different grades of oil sands. The high and low recovery cases represent best and worst case scenarios derived from published data for the HW process. An important observation in this data is that although the SESA tailings contain a higher percentage of solvent than the corresponding HW tailings the former are dry while the latter are associated with a large amount of water. In Table III solvent contents of tailings are compared as a percent loss of a constant SCO production, regardless of oil sands feed grade. Because naphtha is introduced into the HW process only after the bulk of the solids have been discarded the solvent loss in the different cases has been assumed to be constant at all feed grades, i.e. as a constant percentage of the same SCO production. This assumption may not be correct as the bitumen froth produced from lower grades of oil sand probably contains more fine solids which will retain proportionately more solvent during clean up by centrifugation. In the SESA case solvent is added at the front end of the process and the greater solvent losses for lower grades of oil sand simply reflect the larger amounts of ore that must be processed in order to maintain a constant SCO production.

As mentioned earlier solvent extraction processes are capable of maintaining high bitumen recoveries for all grades of ore. Although processing only low grade ore is not, of itself, an economic proposition the ability to maintain high bitumen recovery while processing variable feed, including low grades, is an important operational consideration. Figure 2 compares bitumen recovery results for the SESA and HW processes. The SESA results are straightforward, showing an almost constant recovery at all feed grades. In the case of the HW process the results are more confusing largely owing to the paucity of hard recovery data to be found in the public domain. The series of curves shown on the figure summarise all published results available for current and proposed Syncrude operations. The curves and their extrapolations fall into two regions, which have been designated the HW high and low recovery cases. All economic comparisons between the two processes have been made for both of these cases.

Regardless of which set of results is considered it is apparent that recovery of bitumen by the HW process decreases dramatically as the ore grade drops below 9 w/w% bitumen; this is not so for the SESA process. While this difference in process behaviour may not be too important in the development of leases averaging 10% bitumen or

more it could be very significant in the exploitation of the so-called second tier leases. These leases have lower overall bitumen content and greater amounts of difficult ore such as that with high fines content or deposits laid down in a marine environment.

AOSTRA and NRC Sponsored Program

AOSTRA and NRC have jointly sponsored the latest stage in the development of the SESA process to the extent of $1,000,000. These funds are being used for a three-phase engineering and cost study. Phases 1A and 1B are now complete, at a cost of $303,000 and $254,000 respectively. Phase 1C is underway and is expected to be completed by April-May, 1990.

Phase 1A

This initial phase involved the collection and critical review of all earlier bench and pilot scale data on the SESA Process and the preparation of a preliminary design and cost estimate for a demonstration plant. This work was done by Endeco International Ltd. and Kilborn Energy Inc.

Endeco and Kilborn reviewed the extensive engineering, laboratory and/or pilot tests carried out by NRC, Cambrian Engineering, MHO International and Petro-Canada on various aspects of SESA. Also, comprehensive tests on the recovery of the naphtha solvent from the agglomerated solids were conducted (11,12). Terra introduced a new concept for the removal of solvent from the agglomerated solids and this promises to reduce significantly the cost of solvent recovery. Phase 1A included a detailed process flowsheet, the sizing and preliminary design of the major equipment, and a preliminary cost estimate for a ten-tonne-per-hour demonstration plant (13).

The purposes of the demonstration plant are:

1. To confirm on a large scale the ability of the SESA Process to treat oil sands of varying grades (6-14 percent by weight of bitumen) and obtain high yields (92-96 percent).
2. To test the economic viability of the process and all the ancillary operations such as the recovery, for reuse, of the naphtha solvent from the solid tailings.
3. To verify design and scale-up factors for optimum equipment design and selection for a commercial plant.

Phase 1B

The second phase of the work sponsored by AOSTRA and NRC, also conducted by Kilborn, involved a technical and cost comparison between the SESA Process and the Hot Water Process currently used by Syncrude and Suncor. The purpose of this phase was to determine, before further funds were expended, whether the SESA Process would be economically competitive with the Hot Water Process on a commercial scale. The study incorporated mining, extraction, and upgrading of the recovered bitumen to synthetic crude at a rate of 30,000 barrels per day (14).

Technical Results

The following quotations from the Kilborn report summarize the technical results.

"TECHNICAL AND ENVIRONMENTAL MERITS OF THE SESA PROCESS

1. High bitumen recoveries are indicated at all feed grades.
2. Low makeup and recirculating water requirements.
3. Negligible water contamination and water disposal problems.
4. No chemical addition required.
5. Produces warm, damp, non-dusting solid tailings suitable for direct disposal to mined-out areas, avoiding the necessity of large tailings impoundments.
6. Permits earlier site reclamation.
7. The bitumen from the SESA Process has a lower solids and water content than that from the Hot Water Process.
8. Utility plant required is simpler and less expensive.
9. Winterization requirements are expected to be less due to the lower water content of the streams."

"DISADVANTAGES OF THE SESA PROCESS

1. With naphtha solvent introduced at the front end of the process, vapour-tight equipment and an extensive, safe vapour recovery system is required. This will require an extension of known technology and will require prudent mechanical design.
2. While proven on a bench pilot scale, the process is not proven on either a demonstration or a commercial scale."

Economic Results

The economic objective of the Phase 1B study was to make a practical comparison of the economics of the HW and the SESA processes, each operating at commercial rates producing 30,000 barrels per calendar day of synthetic crude oil and each meeting required environmental standards. For the HW process two possible environmental standards were considered: Case I corresponding to the current and projected operations of Suncor and Syncrude and Case II corresponding with anticipated more stringent requirements for the next generation of mining-extraction plants. The cost comparison is for

complete, integrated plants, one utilizing the HW extraction process and the other the SESA process. Each complex includes mining, extraction, tailings handling, upgrading, utilities, common facilities and site reclamation. The cases considered include three feed grades with corresponding recoveries and, for the HW process, two different recoveries for each of the 8.0 and 6.0 percent grades as well as the different tailings handling and site reclamation programmes reflecting the two environmental standards. The economic analysis covers the capital costs, the annual operating costs over the producing life of the projects, and the continuing site reclamation costs beyond the producing period. The capital costs include initial capital expenditures over the 5 year construction period, the sustaining capital expenditures and the post production reclamation capital costs. The capital and operating costs for an 11.6% grade feed, on a unit of production basis (1989 dollars per barrel of synthetic crude oil) are compared to other unit production costs presented in Table IV. The cost figures are considered conservative and include generous contingency allowances but exclude any government support. The relative values of the HW costs compared with the SESA costs are considered more significant than the absolute values. This is because of the normal margin of error in the estimates including the common or nearly common costs of upgrading and off-site facilities. Additionally, the absolute figures, based on plants of 30,000 b/d capacity are undoubtedly higher than they would be for larger sized plants.

The differences between the HW and the SESA unit production costs for both the low and the high HW recoveries are presented in Figure 3 for the Case I HW Tailings Handling and reclamation and in Figure 4 for the Case II HW Tailings Handling and Reclamation. The Case II situation, reflecting anticipated environmental standards, is considered the more realistic and appropriate for comparison purposes. Figure 4 shows that, for Case II, the SESA unit costs are lower than that of the HW process by some $1.54 per barrel of synthetic crude oil for an oil sand feed grade of 11.6% and range to well above $10.00 per barrel at lower grades and even at intermediate levels of recovery.

Phase 1C

The third phase of the NRC-AOSTRA sponsored program is the definitive design and final (± 10%) cost estimate of the demonstration plant. This work, with Kilborn, is underway. The estimated cost of Phase 1C is $413,000 and completion is scheduled for April-May 1990. The plant is to be located in the Fort McMurray area. Two possible sites are under final consideration. The design of the plant incorporates extensive instrumentation and data logging facilities to ensure that adequate data may be obtained.

Demonstration Plant

The preliminary estimate of the capital and operating requirements for the demonstration plant developed in Phase 1A was some $10.5 million and $6.6 million respectively. Details of these figures, based on a Fort McMurray location, are given in Tables V and VI. It is assumed that the value of the recovered bitumen would offset the cost of oil sand feed. These costs are being refined in the Phase 1C study.

Table VII summarizes the expenditures which have been made to date and the funding required for the demonstration plant. This funding has not yet been arranged but Terra will be seeking an oil industry partner to share with it, and the Alberta and Federal governments, in the cost of the plant. Such a partner would also share in the royalties and other benefits from the licensing of the process.

Terra expects the plant will be constructed during the fall and winter of 1990 with operation planned for the summers of 1991 and 1992. The overall development schedule is depicted in Figure 5.

Conclusion

The SESA Process holds unusual promise as a worthy successor to the Clark Hot Water Process. From the viewpoint of resource recovery its 93-97 percent efficiency can hardly be exceeded. Environmentally, the process is essentially benign, water consumption is minor and there is no water contamination. Land surface disturbance does occur but the dry solid tailings may be returned directly to the mined-out area, permitting complete surface reclamation during production operations. No tailings ponds are required.

The planned demonstration plant is expected to prove out each of the process steps on a substantial scale and to confirm that the process can compete economically with any environmentally acceptable variation of the Hot Water process.

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Table I: Bitumen Quality Comparison

Sample	Bitumen w/w%	Water w/w%	Solids w/w%	Solvent w/w%
SESA (Med. Grade)	47.4	ND†	0.3(0.6)*	52.3(Varsol)
SESA (Med. Grade)	51.6	*	0.3(0.5)	48.1(Naphtha)
SESA (Med. Grade)	48.7	*	0.1(0.2)	51.2(Toluene)
SESA (High Grade)	47.8	*	0.4(0.8)	51.8(Varsol)
Hot Water Process	56.9	5.5	0.6(1.1)*	37.0(Naphtha)

* Numbers in parenthesis are solids on bitumen basis; specification is 0.5 %
† Not detected; detection limit 0.2 w/w%

Table II: HW and SESA Tailings Composition

EXTRACTION PROCESS	HW					SESA		
OIL SAND FEED GRADE %	11.6	8 High*	8 Low*	6 High*	6 Low*	11.6	8	6
Bitumen % by weight	0.44	0.74	1.44	0.85	1.38	0.6	0.5	0.4
Solvent % by weight	0.11	0.06	0.04	0.03	0.02	0.25	0.25	0.25
Water % by weight	40.0	48.3	53.7	56.2	61.8	6.0	6.0	6.0
Minerals % by weight	59.5	50.9	44.8	42.0	36.8	93.2	93.3	93.4

* Recovery Cases

Table III: HW and SESA Solvent Losses

EXTRACTION PROCESS	HW					SESA		
OIL SAND FEED GRADE %	11.6	8 High*	8 Low*	6 High*	6 Low*	11.6	8	6
Solvent Losses; % by weight of SCO Produced	1.9	1.9	1.9	1.9	1.9	2.7**	3.9**	4.8**

* Recovery Cases
** Based on 0.25% specified loss in the tailings

Table IV: SESA/HW Extraction Process Design and Cost Comparison Study

Unit Production Costs By Plant Area (Can. $/Barrel SCO)			
	Process	SESA	HW
	Feed (t/h)	2210	2240
Description	Grade (%)	11.6	11.6
	Recovery, %	94.2	93.0
Case I Tailings Handling & Site Reclamation			
1. Mining		6.72	6.81
2. Extraction		4.86	2.75
3. Tailings Handling		2.14	1.61
4. Upgrading		6.17	6.17
5. Utilities		3.46	3.82
6. Plant Offsite Facilities		8.00	7.89
7. Site Reclamation		0.10	0.19
- Unit Production Cost - Case I		31.45	29.24
Case II Tailings Handling & Site Reclamation			
1. Mining		6.72	6.81
2. Extraction		4.86	2.75
3. Tailings Handling		2.14	5.45
4. Upgrading		6.17	6.17
5. Utilities		3.46	3.82
6. Plant Offsite Facilities		8.00	7.89
7. Site Reclamation		0.10	0.10
- Unit Production Cost - Case II		31.45	32.99

Note: Unit production cost includes all costs - capital and operating - discounted at 10%; production discounted at 10%.

Table V: SESA Demonstration Plant - Preliminary Capital Cost Estimate

Description	Amounts ($1,000)	
Facility Costs		
Plant Equipment		2,430
Equipment Installation		300
Process Installation		2,766
Buildings & Structures		995
Civil works		449
	Total Field Cost	6,941
Construction Management		250
Design Engineering		750
Project Management & Services		250
	Total Facility Cost	8,190
Other Capital Items		
Solvent Recovery Facility		613
Working Capital		160
Startup & Commissioning		270
Reclamation & Salvage		(500)
	Subtotal	8,733
Contingency @ 20%		1,747
	Total Capital Cost	10,481

FROM KILBORN ENERGY INC.

Table VI: SESA Demonstration Plant - Preliminary Operation Cost Estimate

Description	Quantity	Cost($1,000)
Bitumen Production	44,248 bbl	
Tailings	60,950 t	
Operating Costs		
Labour		
Manual Labour	392 mm	1,411
Staff Labour	288 mm	1,584
Feedstock	68,100 t	—
Solvent	1,190 bbl	36
Utility Purchases		
Electricity	153 kWyr	67
Natural Gas		50
Nitrogen		50
Water & Sewage		50
Other Operating Supplies		98
Lab & Assay Services		500
Office Operation		187
Maintenance Cost		740
Local Taxes & Insurance		318
Front End Loaders		221
Subtotal Operating Costs		5,312
Contingency @ 25%		1,328
Total Operating Costs (2 seasons)		6,640

FROM KILBORN ENERGY INC.

Table VII: Proposed Consortium for Demonstration Plant and Licensing

PARTICIPANT	ROLE	$ INVESTMENT, MILLION TO DATE	REQUIRED
NRC/TERRA	Process Conception Process Development Business Development Financial Support	10.5	
AOSTRA	Technical Support Financial Support	0.5	5.0
FEDERAL*	Financial Support		5.0
OIL INDUSTRY PARTNER	Financial Support Management Support		8.0
	TOTAL	11.0	18.0

* Western Economic Diversification Office or Other

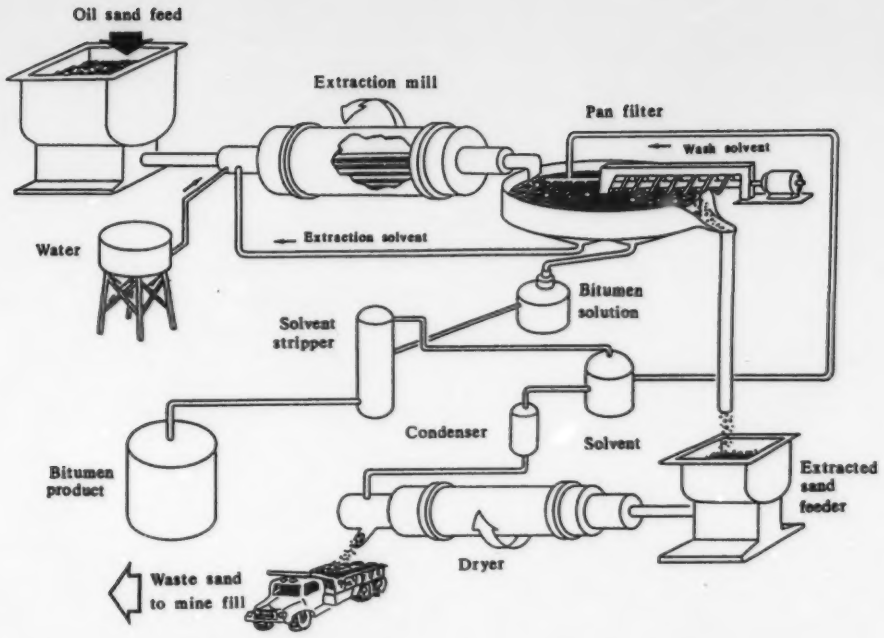

FIGURE 1: SESA simplified process flow diagram.

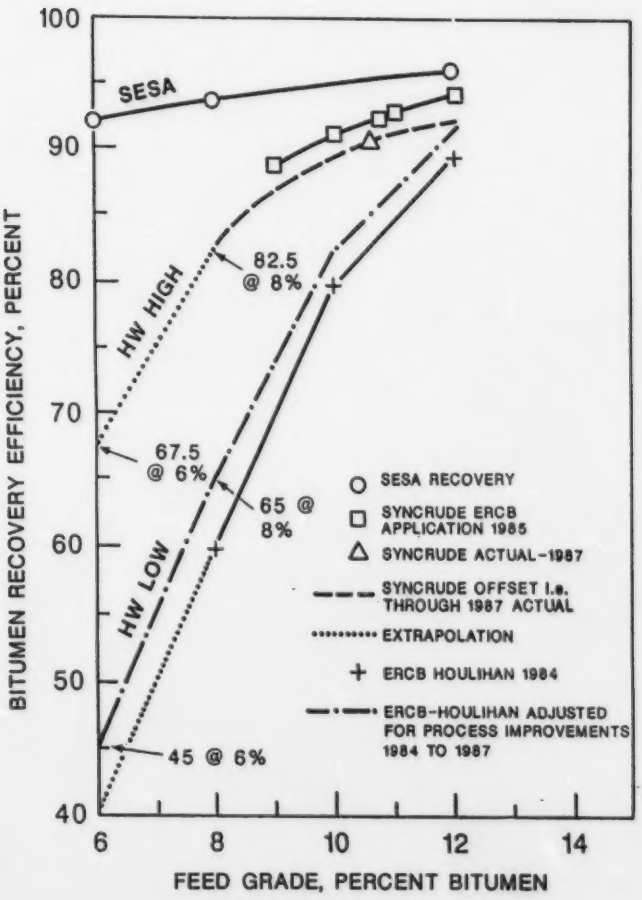

FIGURE 2: Comparison of bitumen recovery efficiencies

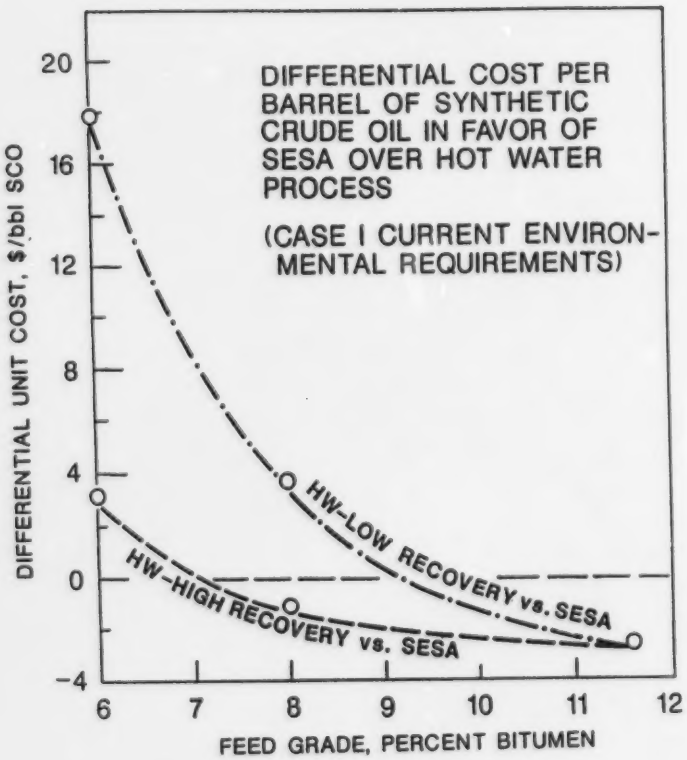

FIGURE 3: SESA and HW processes, differential cost comparison.

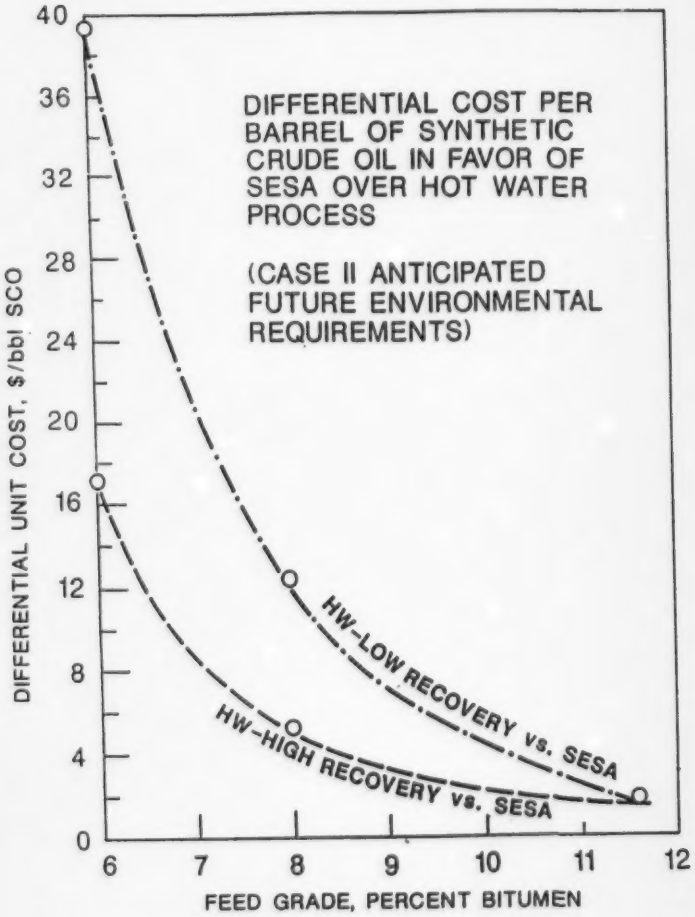

FIGURE 4: SESA and HW processes, differential cost comparison

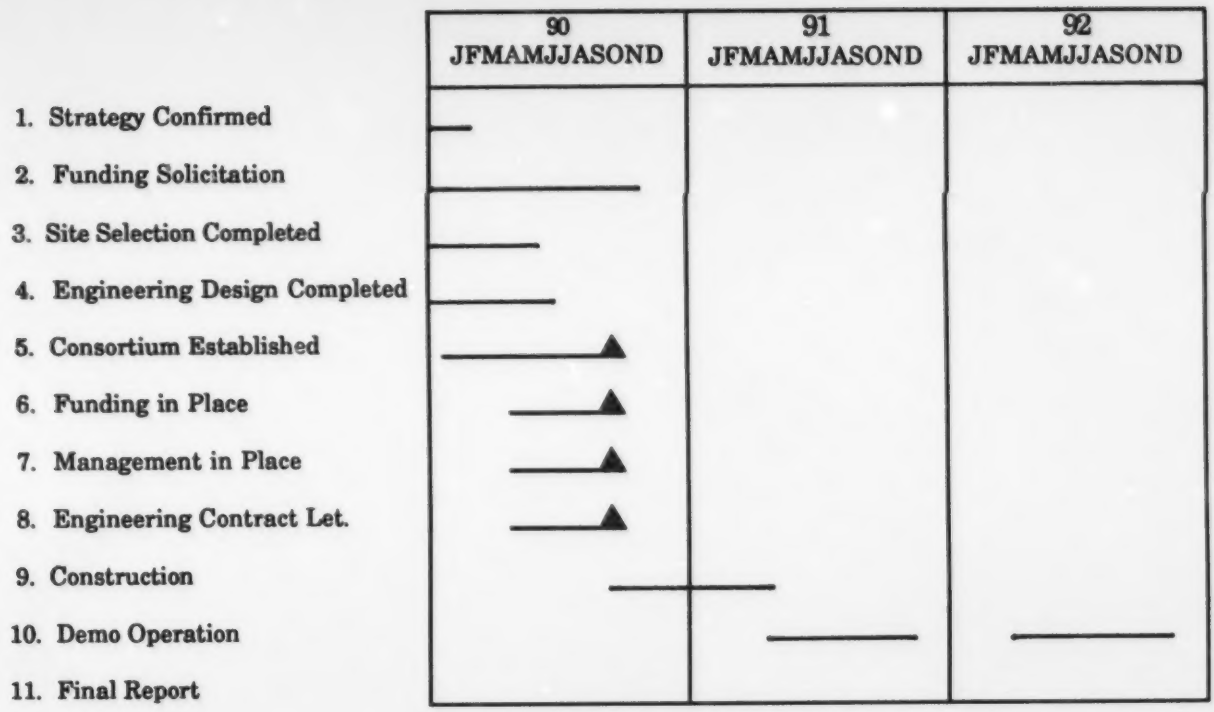

FIGURE 5: SESA Demonstration plant, overall development schedule

Session 2

Paper no. 6

Oil Sands Extraction: A Dynamic Technology

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Oil Sands Extraction: A Dynamic Technology

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Abstract. The technology of bitumen extraction from oil sands has changed dramatically from the initial implementation of the Clark Hot Water Process in the original SUNCOR (formerly Great Canadian Oil Sands) and Syncrude plants. All aspects of performance have improved - from bitumen recovery through plant service factors. This paper defines the state of the commercial extraction and froth treatment technology in the areas of hydrocarbon recovery, water and energy usage, diluent naphtha losses and product quality, and provides a benchmark for the comparison of alternative process proposals.

Areas covered are steam and water requirements for the process, bitumen losses to the tumbler rejects, bitumen losses to the main tailings streams and bitumen and diluent naphtha losses to the froth treatment plant tails. The issue of generation of sludge in the extraction process is covered.

INTRODUCTION

The hot water extraction process is the standard process for recovering bitumen from oil sands. Since it's inception with the work of Dr. Karl Clark at the Alberta Research Council in the 1920's, it has been refined and has been used in the two commercial plants (SUNCOR and Syncrude) in the Athabasca oil sands, and has been the process of choice in all of the major proposed surface oil sands projects (Alsands, Canstar, Syncrude Expansion, OSLO).

The process was developed from Clark's concepts using pilot plant operations that were carried out in the early 1960's, first by the group led by Cities Service Athabasca and then by Great Canadian Oil Sands near the site of the commercial plants north of Ft. McMurray. The major process steps that were developed in these pilot operations have remained essentially the same to this day.

Oil sand is digested and conditioned in large tumblers with the addition of water, heat and caustic. In the resulting slurry, the bitumen is separated from the sand and is aerated to produce a froth that will readily separate from the slurry in the next process stage.

Slurry from the tumblers is screened to reject oversize material (predominantly rock and clay), and is fed after dilution with water to the primary separation vessels where the aerated bitumen froth rises and is collected in launders. A middlings stream containing bitumen that was not aerated in the conditioning process is fed to a second stage of froth flotation. Tailings from both the primary and secondary stages are pumped to a pond where the sand and a considerable portion of the fine clay material is deposited in beaches. Beach runoff is clarified for reuse and the remaining gel-like sludge is stored.

The bitumen froth that is produced by the extraction plant contains about 33 percent water and 9 percent solids by weight. It is further processed in a froth treatment plant to remove the majority of this water and solids. A solvent (naphtha) is added to the bitumen to modify the density and viscosity of the hydrocarbon phase, and in the existing plants, coarse solids are removed using scroll centrifuges while water and remaining fine solids are removed using disc centrifuges. The small amount of residual water and the diluent naphtha are separated from bitumen in a diluent recovery unit. The tailings from the froth treatment plant are sent to a tailings pond.

ALTERNATIVE PROCESSES

Over the years, many alternatives to the hot water process have been suggested. Most of these have been catalogued in the 1984 Dynawest study that was done for the Alberta Energy Resources Conservation Board. These alternatives have included modifications to the basic hot water process, solvent extraction, and thermal and agglomeration processes.

Many of these alternatives have been suggested and justified on the assumption that the hot water process has many serious drawbacks. These include poor recovery from ores with low bitumen content, high energy use and production of waste sludge.

Each of these processes has been compared to the commercial standard - the hot water extraction process. The purpose of this paper is to provide a definitive statement of the hot water extraction performance so that appropriate and accurate comparisons can be made.

EVOLUTIONARY DEVELOPMENT

The development of performance improvements in the hot water extraction process has been evolutionary, and is still continuing. The state of hot water technology that is actually implemented in the plant always lags the state of the technology that is proven in the laboratory. The implementation of new changes require the investment of capital and may have to wait for a "window of opportunity". Because of the evolutionary development of the technology, there is a high degree of confidence that the laboratory developments can be successfully implemented in the plant with predictable performance. Scale-up factors of over 2000:1 have been used successfully.

The same degree of scale-up confidence does not exist with new processes, particularly where material handling issues are involved. In making comparisons between established and newly developed technologies, it is essential to keep these issues in mind.

PERFORMANCE MEASURES

A number of performance measures can be used to give a quantitative basis for comparing alternative extraction technologies. In the past, alternative technologies have sometimes been compared using only one of these measures with misleading results.

Recovery

It will be helpful to begin by establishing the context in which Syncrude's extraction recovery performance has meaning.

Figure 1 shows the insitu distribution of bitumen on Syncrude's lease 17 by oil sand grade. The great majority of the bitumen is in sands containing in excess of eight percent oil by weight. The cost of mining and disposing of sand in an open pit mine is well defined once the geology of the lease is known. Current economic cutoff grades for oil sands operators in the Athabasca region are in the range of six to eight percent (Figure 2).

Figure 3 shows Syncrude's distribution of bitumen above their cutoff grade of six percent. Fully 90 percent is in sands containing more than eight percent oil by weight. It is the recovery in this region that is of critical importance - not the recovery for the lower grades of oil sand.

While it is common to report fractional recovery of bitumen against ore grade (as in Figure 4), this approach tends to obscure the material handling problem. More helpful (1) is to report the yield of bitumen per tonne of oil sand processed as in Figure 5.

Energy Use

The amount of waste heat available for extraction is project specific and highly dependent on the upgrading technology selected. When evaluating alternate extraction technologies, it is important to consider not only the total quantity of energy used, but also the source and value of that energy.

Tailings Properties

The distribution of fine solids in Syncrude's extraction streams in 1989 was such that 53 percent of the fines in tumbler feed reported either to tumbler rejects or were captured in sand beaches. Forty-three percent reported directly to beach runoff (Figure 7). The fine solids in the runoff form the tailings sludge.

As Figure 8 suggests, a powerful incentive exists to minimize water use in extraction and to maximize the density of coarse extraction tailings,thereby capturing a larger proportion of sludge forming fines in the sand beaches. Water usage in the Syncrude plant has declined from 77 Tonnes per 100 Tonnes of oil sand in 1980 to 59 Tonnes per 100 Tonnes in 1989.

THE TECHNOLOGY

At Syncrude there have been continuing efforts at improving the plant operation as described by these performance measures. Integral to this improvement has been the development and implementation of several major technological advances.

Tails Oil Recovery vessels were installed in 1985 (3). Despite an extended commissioning period, further reduction in tails oil losses was evident by 1986 (Figure 14). Tails oil losses for the 1987 through 1989 period were down 2.5 percent from the 1983 through 1985 period (Figure 14). Resolution of some known problems will improve the recovery even further.

Froth treatment bitumen losses (Figure 15) increased from 1.7 percent just prior to completion of the Tails Oil Recovery project to about 2.0 percent for the 1987 through 1989 period. Recovery of oil heavily loaded with solids may be a mixed blessing. Consequently, efforts are currently underway to improve the quality of froth produced in the Tails Oil Recovery Systems.

A vacuum steam stripper (Naphtha Recovery Unit) was developed to reclaim diluent naphtha from the froth treatment tails. This unit was commissioned in 1985 and recovers approximately 65 percent of the naphtha that would have otherwise gone to the tailings pond.

Inclined plate settler technology has been perfected for three phase separations to permit an increase in froth treatment capacity and efficiency without the addition of new centrifuges (4). The static inclined plate settlers are much simpler units to operate and maintain than centrifuges.

As part of recent Syncrude Expansion Study (5), a lower temperature version of the hot water extraction process was developed, piloted and tested in the plant. This process (the warm slurry process) operates at a slurry temperature of 50° C.

THE ACCOMPLISHMENTS

Syncrude's accomplishments in extraction, through 1989, encompass both continuous improvements and economies in the operation of the Mildred Lake plant as well as major technological advances in extraction, froth heating and froth treatment for the Syncrude expansion case.

Operations Improvement

Use of sodium hydroxide and extraction water have been managed steadily downward over the years until today caustic dosage averages 0.01 weight percent on oil sand and total water averages 59 weight percent on oil sand. Demulsifier usage in froth treatment has resulted in lower oil and diluent loss and more stable operation.

In an effort to increase extraction plant availability, preventive maintenance schedules have been optimized and every piece of equipment is scrutinized for ways to increase its availability. Wear materials are being used on tumbler lifters, centrifuge scrolls, centrifuge bowls, pump impellers, centrifuge nozzles, tumbler screens and in many other applications.

Availability of extraction feed conveyors is being improved through better belting and detailed analysis of all major subassemblies.

Recovery

The yield curve used in the Dynawest study (2) accurately represents Syncrude extraction performance during 1982. In the intervening years, evolutionary changes have resulted in significant increases in recovery (Figures 4 and 5).

The overall efficiency of the extraction separation circuits (Figure 9) was nearly 96 percent for the 1989 production year. In the beginning, losses to extraction tails were high (Figure 10) and constituted the vast majority of all oil losses.

Due to the continuous increase in tumbler feed rates (Figure 11) over time, oversize rejects (Figure 12) have increased along with oil loss to rejects (Figure 13).

A major effort to improve the flexibility and stability of operation of flotation cells began to impact on flotation tails oil losses in 1982. A permanent reduction in flotation tails oil losses was realized during the 1983 to 1985 period (Figure 14).

Froth treatment diluent losses followed a classical learning curve (Figure 16) with the last major decrement occurring after start-up of the steam stripper for the treatment of froth treatment tails.

Energy Use

Syncrude's extraction process heat requirements are illustrated in Figure 6 for the design operating temperature of 80° C, for the current temperature of 75° C and for the Syncrude expansion design temperature of 50° C. For the 50° C case virtually all of the energy requirements for the process come from waste heat from the upgrader.

Product Quality

Table 1 focuses on the quality of extraction froth just prior (1982 through 1984) to the Tails Oil Recovery (T.O.R.) project, during T.O.R. commissioning (1986) and during a period of relative stability of operation (1987 through 1989) during which the vessels still have not realized their full recovery potential. Clearly, there has been a decrement in froth quality. In the absence of measures to improve the quality of froth produced in the post primary circuits, overall froth quality can be expected to decrease further as recovery from the T.O.R. vessels increases and the overall efficiency (Table 3) of the separation circuits increases from 96 percent to 97-98 percent. Efforts are underway to upgrade the quality of froth produced in the post primary circuits.

Implementation of a 50° C extraction process as defined in the Syncrude expansion study would result in the production of appreciably drier froth (Table 2) than is currently produced at 75° C but at equivalent separation circuit efficiency (Table 3) and at a significantly lower steam requirement (Figure 6).

While pilot studies show that diluted bitumen from Syncrude's expansion froth treatment process contains twice the solids loading as the current process (Table 4), it is expected that further work with chemical additives will both improve diluted bitumen quality and further reduce diluent naphtha losses. Bitumen recovery for this process is, however, remarkable with a drastic reduction in bitumen losses from the current 1.9 percent (Table 4) to a few tenths of a percent. It should also be noted that while naphtha recovery from tails was not attempted during pilot testing, it is anticipated that tailings naphtha would be largely recovered in the steam stripping recovery unit.

THE DEVELOPMENT PROCESS

The development process that was used in making these significant changes to the hot water extraction process has been a continued evolutionary approach that regularly uses actual plant performance to both confirm design decisions and to suggest future directions. This approach has been remarkably productive, with a short time lag between technology development and implementation of changes in the plant.

The complementary roles of process changes and operational improvement and learning are clearly emphasized with this evolutionary approach. Work progresses in an orderly manner with laboratory and bench work completed to an appropriate degree before field piloting is considered. With the availability of the commercial plant for occasional tests, there is a greatly reduced need to move to early (and consequently risky) field pilots.

THE FUTURE

The hot water technology has evolved extensively from it's initial implementation, but is by no means at it's final stage of development. The areas where future changes will occur are in measurement and control of the process (using advanced information technology methods), in combination with hydraulic transport of oil sand (where the initial conditioning will be done in a pipeline rather than a tumbler), and in process simplification.

The hot water process is particularly suitable in an integrated oil sands complex where a large amount of low level waste heat is available from the upgrading operation. For a remote stand-alone bitumen production facility, however, there is a strong incentive for a process that uses even lower temperatures than the 50° C warm slurry version of the hot water process. This will be the greatest challenge for the hot water process, and will provide the ground where alternative technologies may be most competitive.

Production of persistent clay suspensions in tailings water, i.e., sludge is characteristic of virtually all variants of dilute water slurrying processes irrespective of their use of sodium hydroxide. As noted earlier process conditions can significantly alter the quantity of sludge which must be stored.

Syncrude and others are currently engaged in efforts to more thoroughly understand the nature of sludge. In the shorter term, Syncrude is looking at ways to minimize the sludge remaining in final tailings and to have in place suitable reclamation methods for residual volumes.

CLOSING

The evolution of the Clark hot water process is a story of continuing development and improvement. This paper has given a snapshot of it's performance at the current time. It is important when evaluating alternative technologies, to use a comparison with the hot water process in it's current stage of development, rather than as it was initially implemented in either the SUNCOR or Syncrude plants. In these comparisons it is also important to recognize that the hot water process is the only one that has been commercially implemented; it has had to face the test of actual operation, and all the designers hopes and wishes have been (sometimes painfully) tempered by reality.

There will be places for new and revolutionary technology in the extraction of bitumen from the oil sands. The development of these new technologies will be best helped by exposing them to the competition of the best that the hot water process has to offer.

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(2) A study for the Alberta Energy Resources Conservation Board, Oil Sands Bitumen Extraction Process Evaluation, Vol. III, Detailed Evaluation of Selected Processes, Final Public Report, by Dynawest Projects Ltd., pp 66-78 (February 1984).

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(5) P. Ambrose, J. Clark and A. Hyndman, "Selection of Technology for Expansion of Syncrude", CSChE conference (October 1988).

FIGURE 1
PERCENT OF TOTAL BITUMEN IN OILSAND
VS
IN SITU GRADE

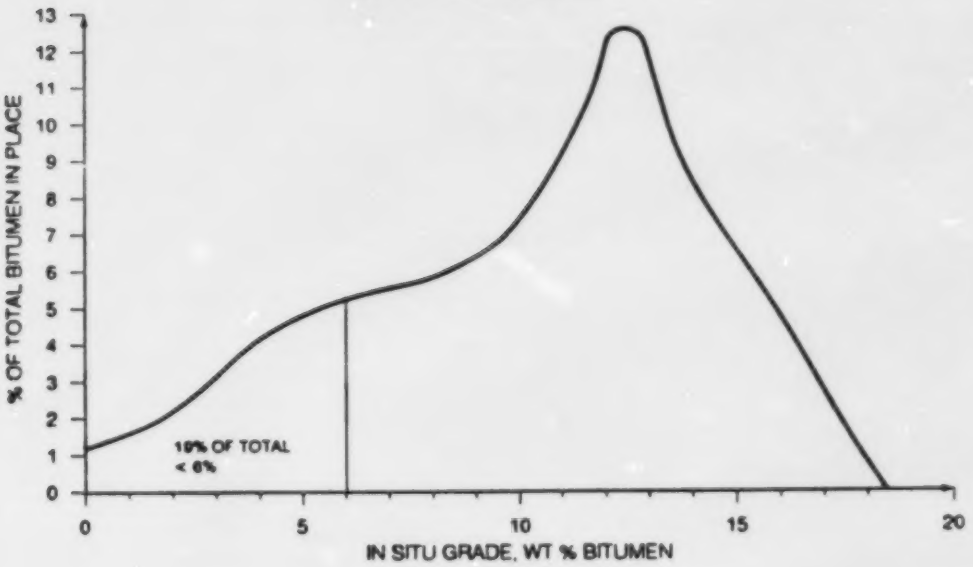

FIGURE 2
TONNES OIL SAND / BBL BITUMEN IN PLACE
VS
IN SITU GRADE

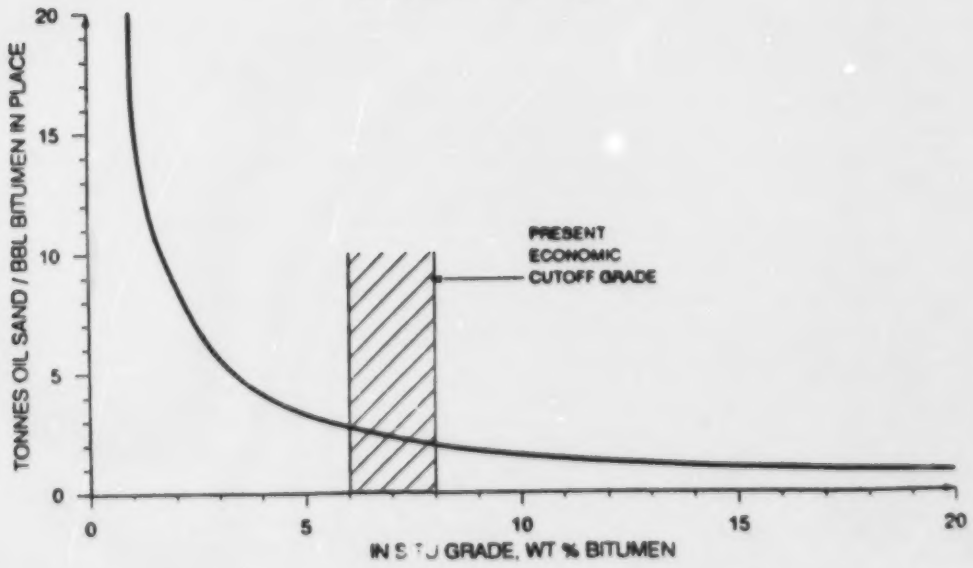

FIGURE 3

PERCENT OF TOTAL BITUMEN IN OILSANDS > 6%

VS

IN SITU GRADE

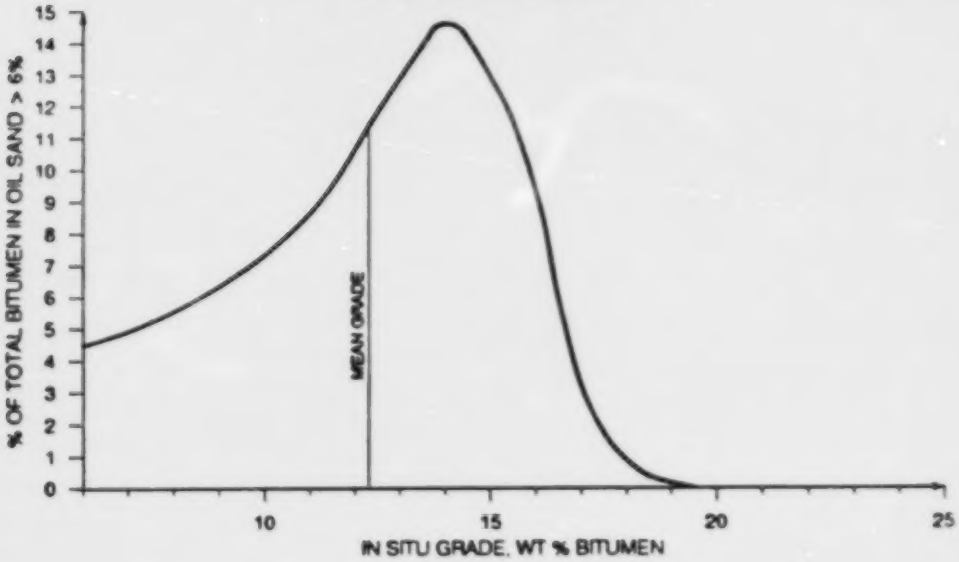

FIGURE 4

EXTRACTION PLANT RECOVERY

VS

ORE GRADE

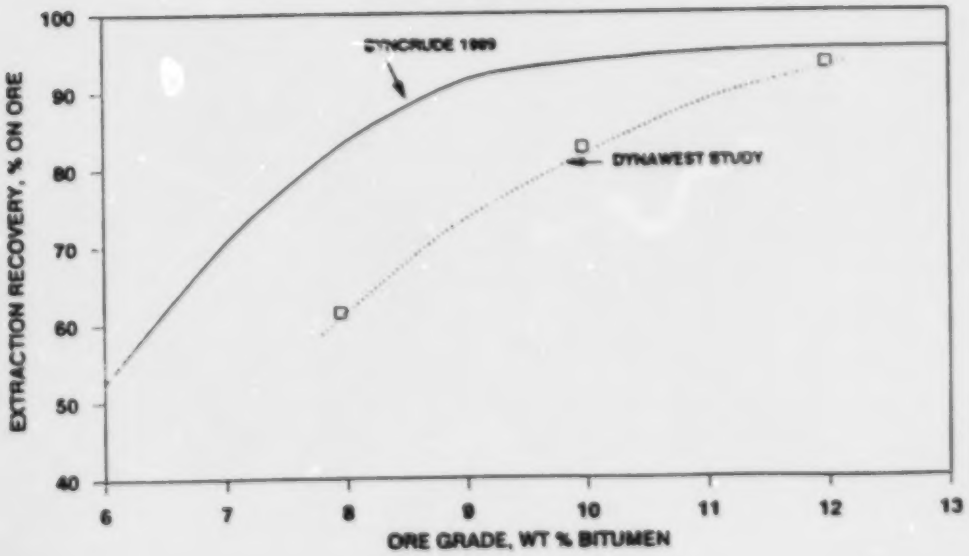

FIGURE 5
YIELD FROM OILSAND
VS
FEED GRADE

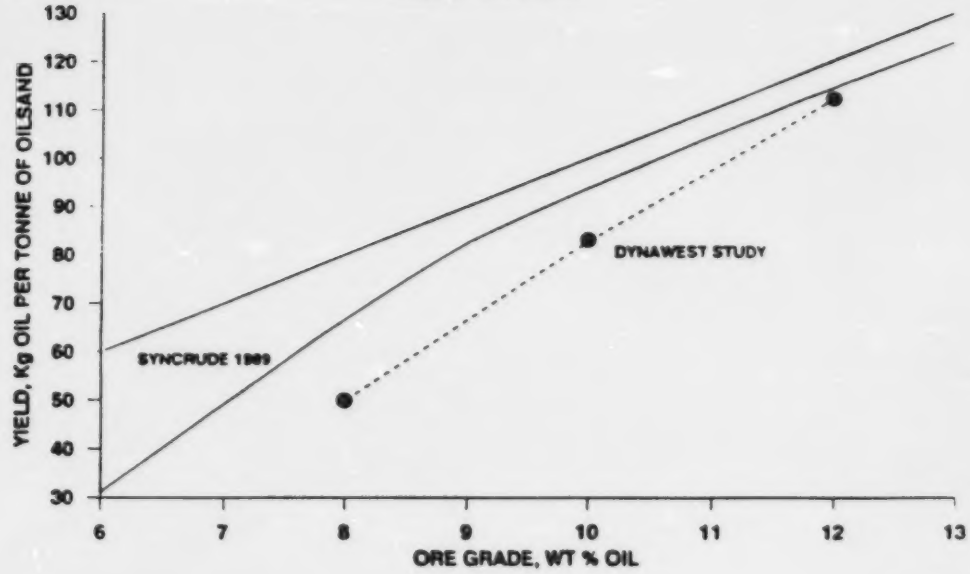

FIGURE 6
EXTRACTION PROCESS HEAT REQUIREMENTS
VS
TUMBLER DISCHARGE TEMPERATURE

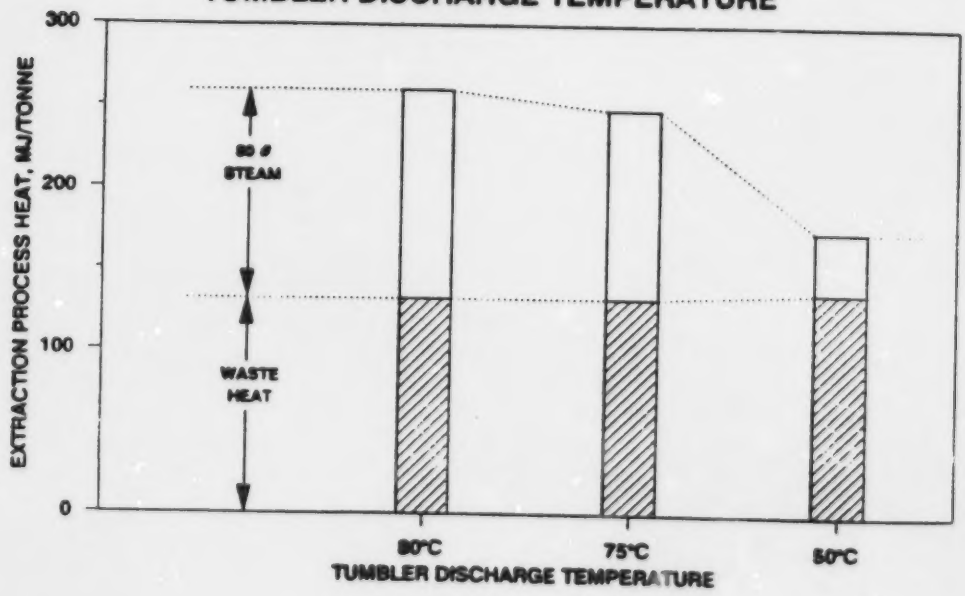

FIGURE 7
1989 FINES DISTRIBUTION

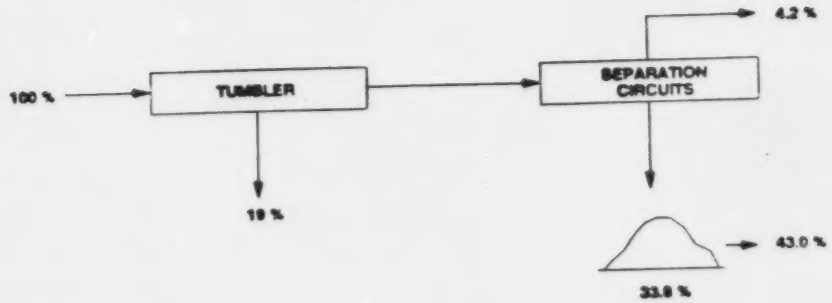

FIGURE 8
FINES CAPTURED IN EXTRACTION TAILS

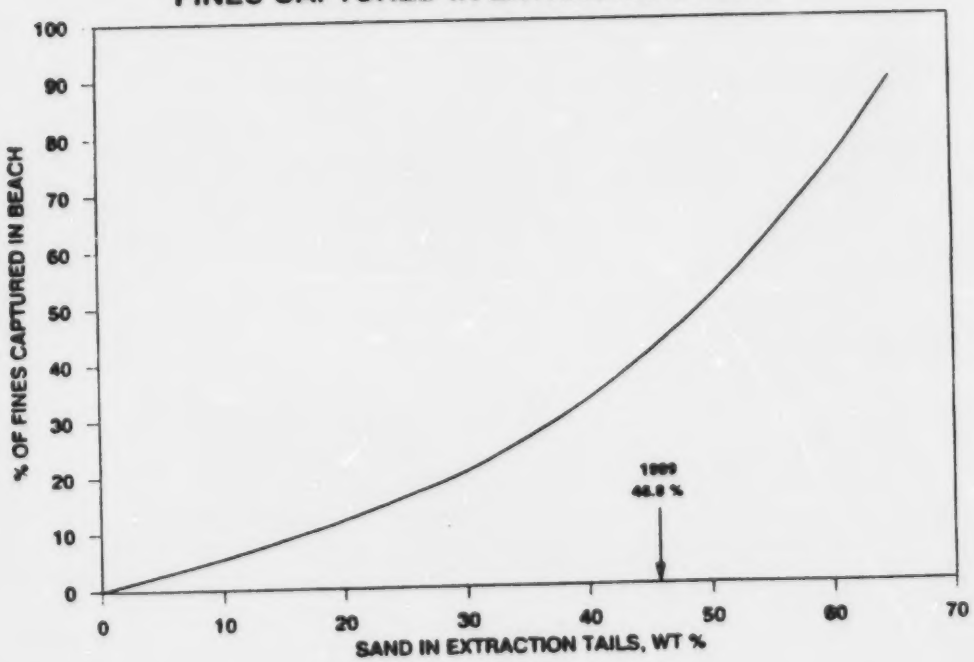

FIGURE 9
BITUMEN DISTRIBUTION IN EXTRACTION

1989

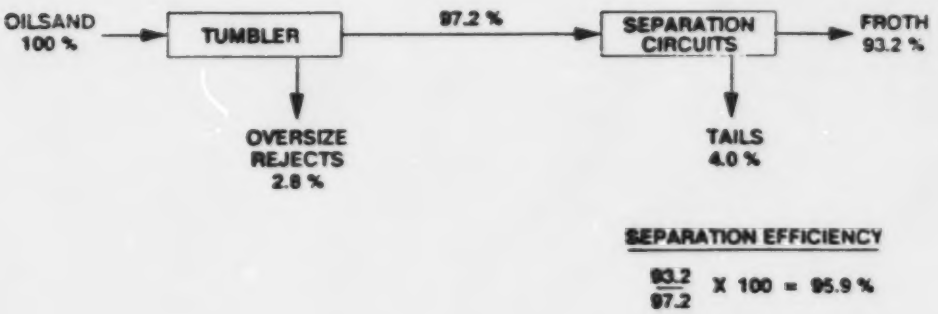

FIGURE 10
EXTRACTION AND FROTH TREATMENT
BITUMEN LOSSES

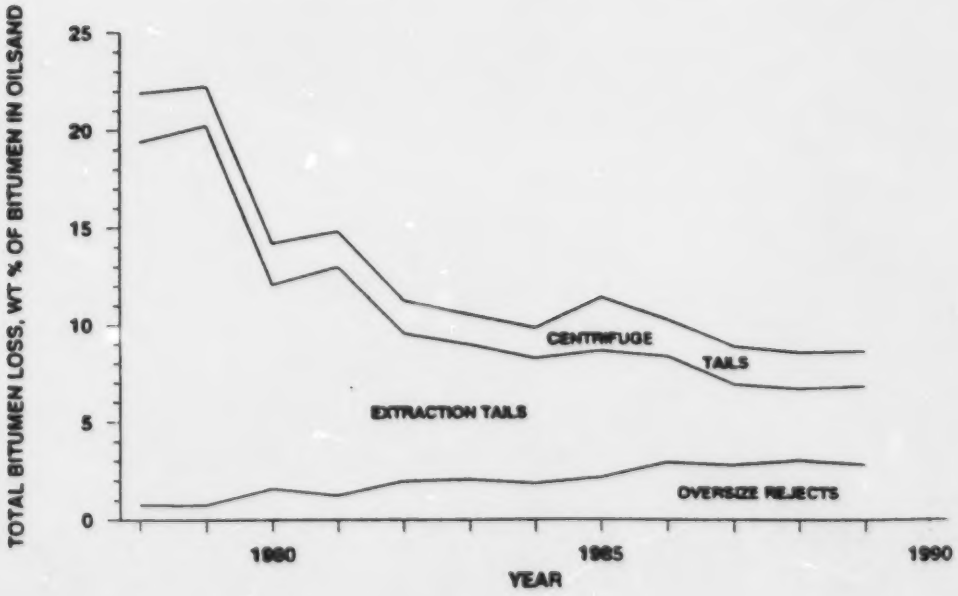

FIGURE 11
OVERSIZE REJECT VS OILSAND FEED RATE

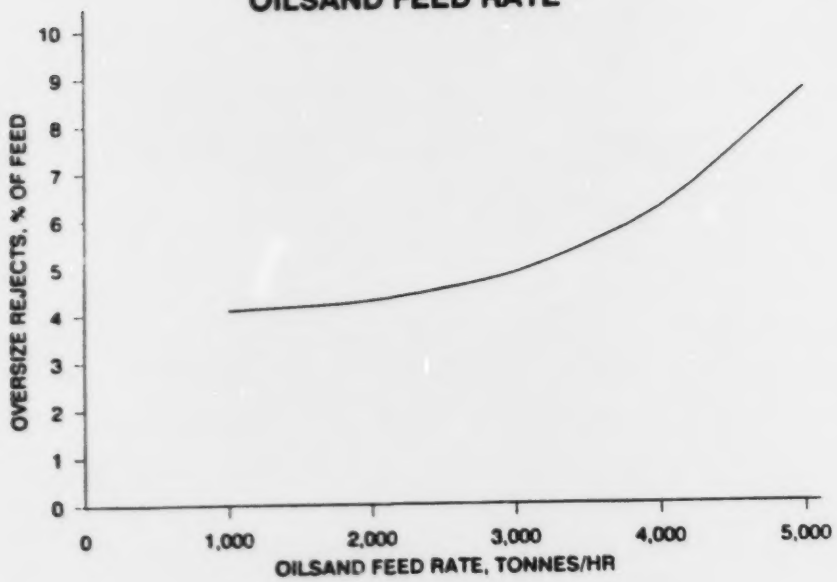

FIGURE 12
OVERSIZE REJECTS

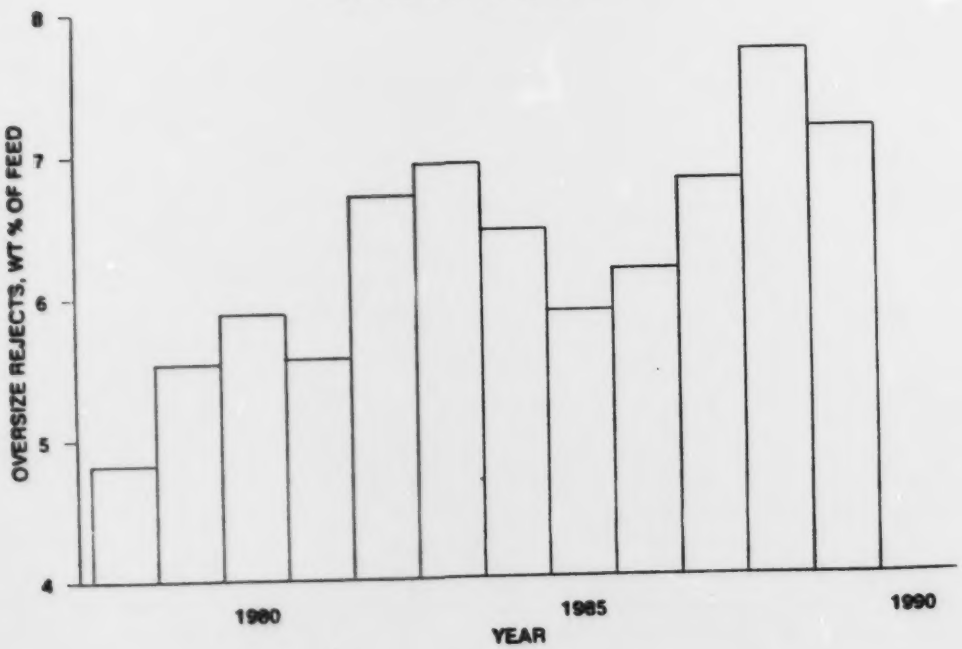

FIGURE 13
OIL LOSS TO REJECTS

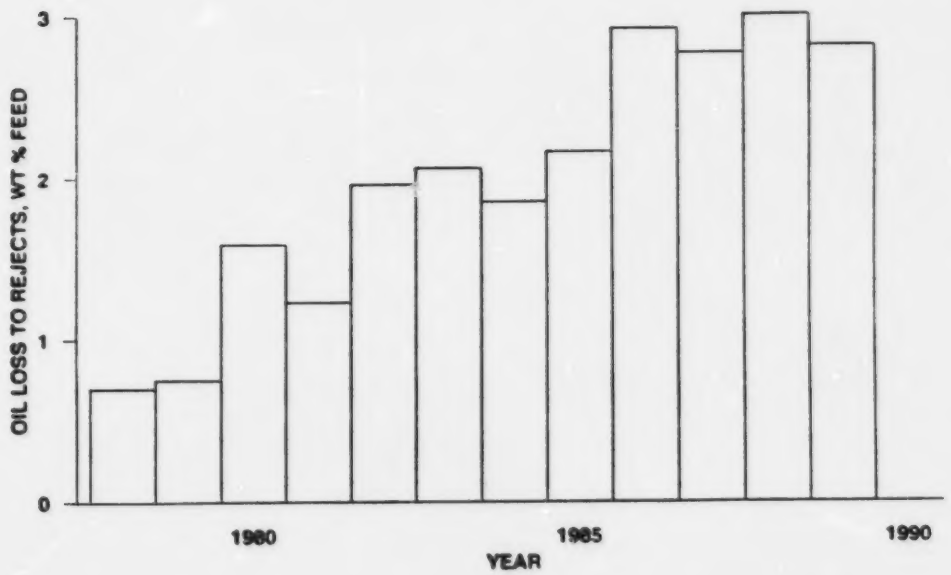

FIGURE 14
EXTRACTION TAILS OIL LOSSES
FROM
SCREENED SLURRY

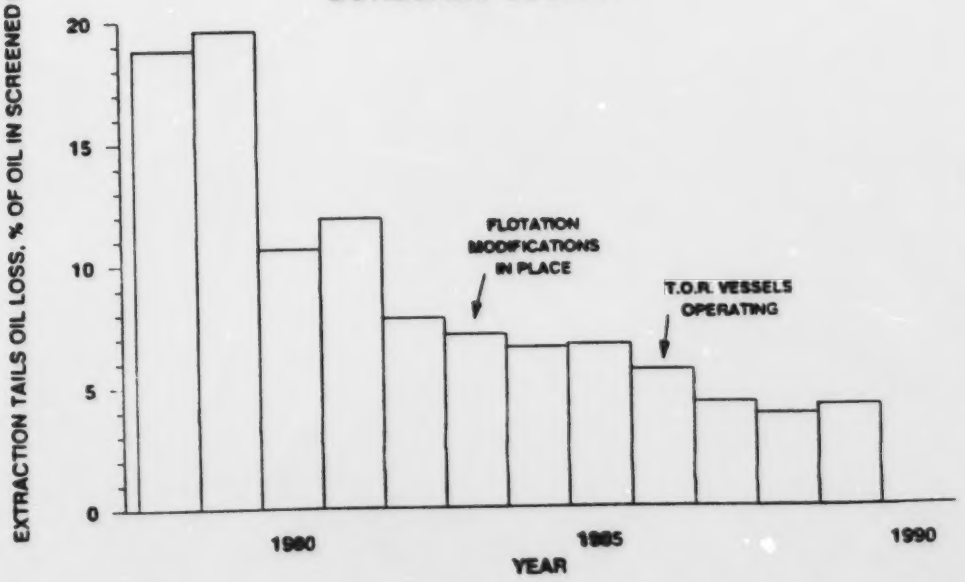

FIGURE 15
FROTH TREATMENT BITUMEN LOSS

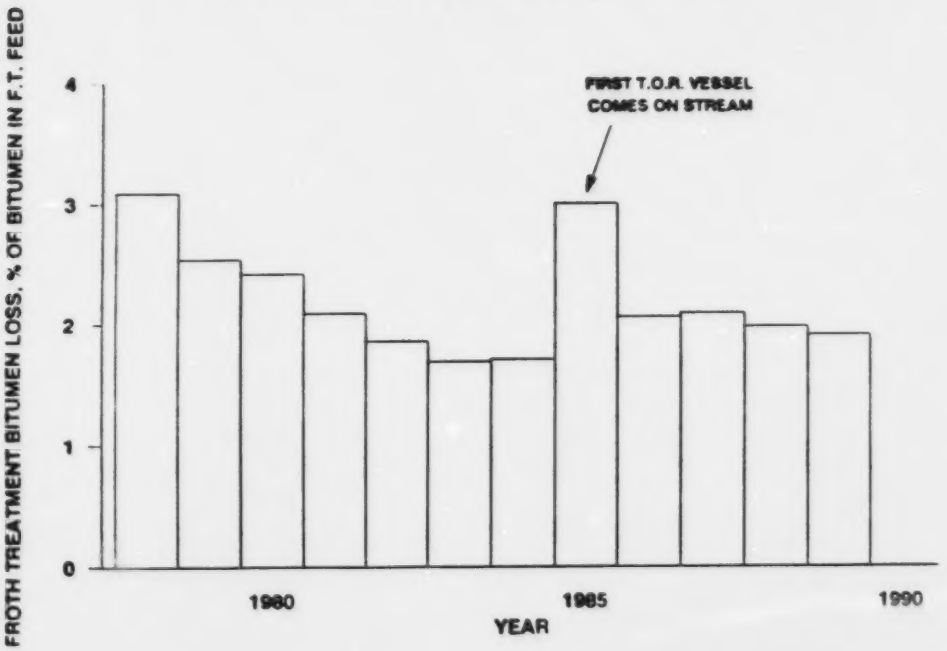

FIGURE 16
FROTH TREATMENT DILUENT LOSSES

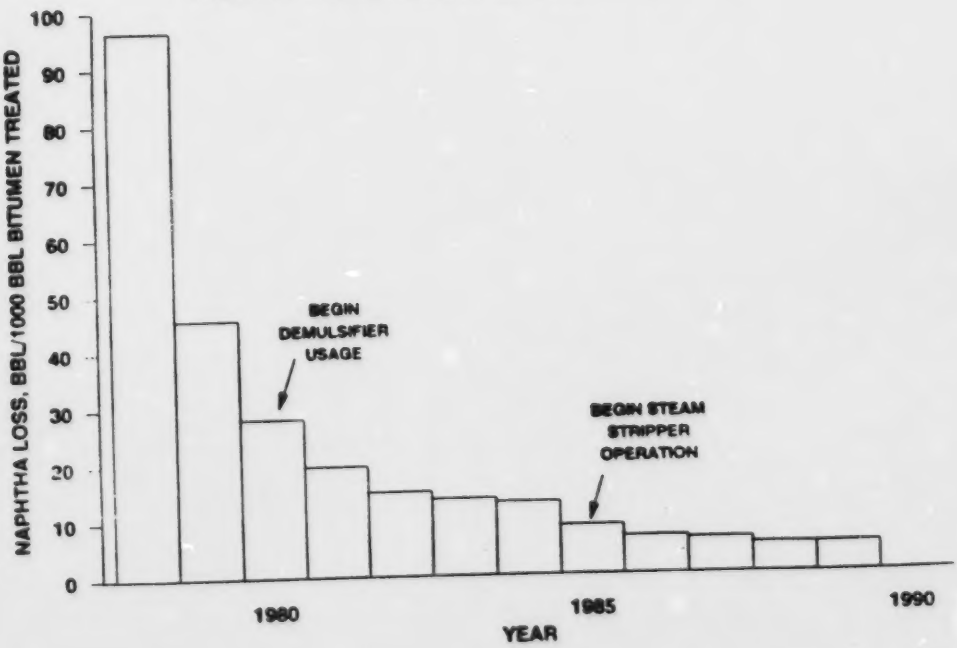

TABLE 1
EXTRACTION FROTH QUALITY

	PRE T.O.R.	POST T.O.R.	
	1982 - 1984	1986	1987 - 1989
OIL, WT%	59.4	56.8	57.5
WATER, WT%	32.0	34.9	33.5
SOLIDS, WT%	8.6	8.3	9.0
S/O	0.144	0.146	0.156
W/O	0.540	0.614	0.584
S/W	0.267	0.237	0.268

TABLE 4
FROTH TREATMENT PERFORMANCE

	1989	3 STAGE MIX/SET	
	COMMERCIAL	75C FROTH	50C FROTH
BITUMEN LOSS, %	1.91	0.26	0.17
NAPHTHA LOSS, %	0.57	0.48 [1]	1.16 [1]
DILUTED BITUMEN			
% HC	94.7	94.1	94.8
% WATER	4.6	4.5	3.9
% SOLIDS	0.7	1.4 [2]	1.3 [2]

1. Assumes 35% loss from stripper. Actual testing not carried out.
2. Demulsifiers not used during pilot testing

TABLE 2
FROTH QUALITIES
WT %

		50°C PLANT TRIAL	
	1989 AVERAGE	11 % OIL SAND	9-10 % OILSAND
OIL	58.2	66.5	62.7
WATER	33.1	24.6	27.8
SOLIDS	8.6	8.9	9.5

TABLE 3
EFFICIENCY OF EXTRACTION
SEPARATION CIRCUITS

	50°C PLANT TRIAL	
1989 AVERAGE	11 % OIL SAND	9-10 % OILSAND
95.9 %	96.8 %	95.4 %

AOSTRA Underground Test Facility Achievements And Future Development

J.A. Haston, Project Manager, UTF; N.R. Edmunds, Process Development Coordinator, UTF; R.W. Luhning, Director, In Situ Operations, Technology Transfer and Commercialization; J.C. O'Rourke, Manager, UTF Site, Alberta Oil Sands Technology and Research Authority

Abstract. In situ production from the non-mineable Athabasca oil sands was a cornerstone of AOSTRA's original mandate. The Underground Test Facility (UTF) project initiated by the Authority is proving to be a key to these vast resources.

The project was conceived to investigate and develop thermal process applications implemented through horizontal wells placed low in the oil sands from a tunnel access system in the underlying limestone. It is now completing the first level of process piloting (Phase A) and has achieved some outstanding results.

The Phase A tests have demonstrated the technical feasibility of gravity drainage processes in Athabasca in situ recovery. Economics studies based on these results indicate excellent prospects for commercial scale operations at the UTF site.

AOSTRA, the project operator, is confident that the UTF will make significant contributions to in situ recovery technology and has initiated work on the Phase B level of piloting. This paper reviews the achievements to date and discusses the promising future for the UTF technology.

The Underground Test Facility (UTF) project initiated and operated by the Alberta Oil Sands Technology and Research Authority (AOSTRA) is proving to be a key piece in the Athabasca oil sands in situ recovery puzzle. The project has enjoyed marked technical success and offers good prospects for a profitable commercial scale demonstration at the UTF site. This paper reviews the achievements to date and discusses the promising future for the UTF technology.

INTRODUCTION

When AOSTRA was founded in 1974, surface mining operations in Athabasca were at the commercial demonstration stage. Great Canadian Oil Sands (later Suncor) had been producing for several years, and the huge Syncrude plant was under construction. However, this technology was suitable for application to only about 10% of the deposit. The development of in situ techniques and strategies for accessing the bulk of this huge resource became a cornerstone of AOSTRA's mandate.

In 1976, a Calgary engineering firm, Williams Brothers Canada Ltd., proposed the study of a shaft and tunnel access scheme for in situ recovery from Athabasca.[1] AOSTRA was one of the sponsors of this original Mine Assisted In Situ Process (MAISP) study which investigated adapting Russian thermal mining experience to the more difficult Athabasca application. The shaft and tunnel access approach had as its original objective the 'missing zone' in Athabasca, the vast reserves in those regions of the McMurray formation which were too deep for surface mining extraction operations and too shallow for in situ methods being developed at the time. The key feature of this new approach was to place horizontal wells low in the McMurray formation to drain the heated bitumen. Mine access would provide for economical placement of sufficient wells to give extensive contact with the formation for effective heating, and would promote simplified production operations under drainage conditions.

When the industry group subsequently initiated the first small scale escarpment tests of MAISP,[2] AOSTRA moved on to studies of a larger demonstration project. However, neither the MAISP surface tests nor additional AOSTRA/industry project studies led to an active industry interest in an underground test of the technology.

AOSTRA continued to be of the opinion that some good prospects for the technology could only be evaluated through full underground testing, and in early 1983 took initiative on its own to develop detailed designs for an Underground Test Facility (UTF) project to be located on a Crown lease located 60 km north of Fort McMurray (Figure 1) just beyond

the limits of conventional surface mining techniques. Norwest Resource Consultants Ltd. of Calgary were retained to assist in project development. By May 1984, the initial exploratory drilling had been done and the mine access facilities were designed and specified for bidding.3

At this point AOSTRA went back to industry offering participation in the proposed program. Considerable interest was expressed, but no industry commitments were forthcoming. After much deliberation, it was decided that the technology needed and warranted full underground testing, and AOSTRA committed to fund the construction of the mine access facilities on its own. After eight years of study, mine access technology was about to move to complete field testing in the form of AOSTRA's Underground Test Facility (UTF) Project.

PROJECT DESIGN

The project concept is shown schematically on Figure II. Mine access consists of two vertical shafts sunk through the oil sands to a depth of over 200 meters, from which a tunnel system was constructed in the Devonian limestone underlying the oil sands. The main hoist for personnel, mineral and equipment is located in No. 1 shaft, which also serves as the fresh air intake for the mine. No. 2 shaft serves as the mine exhaust and houses a slower moving Universal hoist intended for emergency egress only.

A custom underground drilling rig was developed to drill upwards at a shallow angle from the tunnel system and then horizontally through the oil sands. Three pairs of wells were drilled and completed for the Phase A tests, each well approximately 160 meters long, with the last 60 meters being open to the formation with one of three test design completions. Each pair consists of a producer lying near the base of the oil sands and an injector about 5 meters above the producer.

Process steam generation and production handling facilities are located on the surface with all process piping connecting to the wellheads through the #2 shaft.

The process technology of horizontal well in situ recovery is the end objective of the project work. The first process selected for testing at the UTF was an application of the steam assisted gravity drainage (SAGD) process. The basic mechanism of SAGD, shown in simplified terms on Figure III, was first demonstrated and analyzed by Butler in 1978.[4] A pair of horizontal wells are placed in the reservoir with the producer near the base of the oil sands and the injector about 5 meters above it. Figure III is a cross-section through the run of these wells.

Steam is injected through the upper well and flows through the highly permeable depleted zone to the cold oil face where it is condensed and gives up heat to the sand and bitumen. The mobilized bitumen and condensate drain by gravity to the lower production well. The depleted zone, or steam chamber, rises and spreads as the pay zone is drained of bitumen.

Since steam is not forced into the formation above fracture pressure, it is contained within the developing steam chamber providing for good conformance and efficient use of steam. Forecasts of process performance were for high recovery at an excellent steam/oil ratio (SOR). The controlling unknown was the effective vertical permeability of the formation and its impact on the rate of production; these factors were the principal subjects of the initial field tests. A detailed account of the engineering of the first SAGD test is given in reference 5.

A second process was added to the field program, Chevron's Heated Annulus Steam Drive process, or HASDrive.[6] It combines features of SAGD gravity drainage with a controlled steam drive to effectively drain the formation. HASDrive was expected to give performance superior to pure SAGD in reservoirs where effective vertical permeability was low or markedly stratified. Thus the two processes could be somewhat complementary, with the choice depending on local conditions.

The process field testing program was planned in two stages. Phase A was aimed at determining critical formation characteristics through the testing of relatively short 'pre-pilot' wells. With success, the program could be expanded to the Phase B level for the testing of commercial length wells in optimized configurations.

ACHIEVEMENTS

To date, the development program has enjoyed marked success. The mining access and underground drilling technology has been demonstrated; the in situ recovery processes are giving outstanding results; and there is a solid indication of potential for profitable commercial scale production at the UTF site.

Mining/Drilling

The shaft and tunnel access concept (SATAC) technology presented new challenges to the Canadian mining and drilling industry. Shafts had to be sunk through the oil sands, a formation that had completely foiled an earlier attempt to put down a test shaft at the Great Canadian site over twenty years ago. Unknowns associated with tunnelling included optimum horizon, required support, the possibility of gas and water emissions, and the effect of process heating on the overall mine integrity. The underground drilling and completion of large diameter horizontal process wells (greater than 125

mm) had never been attempted before.

These challenges have been met.

The main shafts were sunk by blind shaft boring, a method new to Canada, in which the shafts were literally drilled like huge oil wells.[7] One of the largest conventional drilling rigs was extensively modified to handle a 4 meter diameter drill bit and 3.5 meter diameter casing. The shafts were then drilled under mud for stability, cased and cemented off. The method worked well, meeting all specifications within schedule and under budget.

Tunnelling in the limestone was a pleasant surprise. The planned horizon was level and continuously competent, and no serious emissions were encountered. As can be seen from Figures IV and V, the mine fully meets its objective as a safe, operable subway to the wellhead. The year-round 'shirt sleeve' underground environment greatly simplifies operations in Northern Alberta.

The drilling of the process wells was perhaps the biggest challenge. Conventional oil rigs could not work in the confined space of the tunnels, and conventional underground drills were not capable of drilling and completing big diameter oil wells. A custom drilling rig was designed and built in Calgary to do the job. Since the wells were initially drilled upwards at a shallow angle to reach the oil sands and then diverted to horizontal, new techniques and equipment had to be developed for drilling fluid pressure control, well surveys, logging and running casing under pressure. The learning curve was very steep on this unique operation; however, by the end of the program, the wells were successfully completed and a whole new drilling technology had been demonstrated.

The SATAC technology was a major departure for the Western Canadian oil industry, but it has shown its value in fostering the subsequent development of key processes. More detail on the concerns and accomplishments in this novel approach can be found in references 7 and 8.

Process

The UTF exists to develop and demonstrate horizontal well in situ recovery processes, and it has already accomplished much. Both the SAGD and the HASDrive processes have been successfully demonstrated at the Phase A pre-pilot level of operation, and either test represents a major breakthrough in in situ recovery from Athabasca.

The challenge in Athabasca is to cope with a highly viriable reservoir containing some of the most viscous bitumen in Alberta (about 5 million cp at initial conditions) which renders the formation pay essentially impermeable under reservoir conditions. Horizontal wells are proving to be the key to establishing controlled communication through the reservoir for effective heating and drainage of this bitumen.

The principal tool in process analysis and program planning has been numerical simulation of the process mechanisms. Reservoir engineering numerical models provide for efficient rigorous analysis of the complex recovery mechanisms under many variations of formation properties and operating conditions. In this way, sensitivity to various parameters can be established; the uncertainty in these parameters then gives a measure of the uncertainty in forecast performance. This insight is essential to the design of the pilot program and to the interpretation of ongoing observations as the field work proceeds.[5]

The prime process under test in the Phase A operations has been the steam assisted gravity drainage (SAGD) process described earlier. Results from the field testing have been extremely encouraging, both in terms of absolute process performance and in the validation of the program design basis. Specific data is proprietary to the project participants, but the unscaled plots on Figure VI show clearly the excellent fit of actual results with the design plan.

The dashed lines noted as high and low forecasts on Figure VI were set as the expected envelope of performance shortly before the field test was initiated. These forecasts came out of extensive reservoir engineering simulation work and were based on a judgement of the range of reservoir properties that might be encountered. The actual performance of the three well pairs testing the SAGD process is also plotted. The A1 pair experienced a difficult start-up, because of a particularly severe localized shale, but has since tracked the high performance slope closely. The A2 pair came on stream several months later, started up quickly and is now coping with formation conditions more similar to the low forecast reservoir. The A3 pair was further delayed for various experimental purposes, but has recently become a strong producer as well.

The process results are both quantitatively excellent and qualitatively understandable, in the sense that the characteristic behaviors of a gravity drainage process, as predicted by the early simulation work, are clearly present in the field. The major surprise has been the apparently high effective permeability of the reservoir.

As a point of interest, more conservative forecasts made at the time of project commitment, before much of the detailed simulation work had been carried out, were considerably below even the low forecast on Figure VI. In this light, the actual performance of the test well pairs has been a huge success.

In addition to the reservoir performance, gravity drainage to underground access has demonstrated significant production engineering advances. In most applications, production will flow to surface throughout the life of a pattern, thereby eliminating

the need for pumps. Where conditions favor low operating pressures (e.g. where low pressure thief zones are in communication with the pay), a single, conventional process pump will serve the entire operation from a central gathering facility. Further, the relative gentleness of the process makes tight sand control practical. The minor sand accumulations that have been observed were easily removed by briefly surging the wells. As a result of negligible sand problems, and the absence of pumps or any other moving parts within the wellbores, it appears that the need for workovers will be so rare as to argue for abandonment of such wells, rather than investing in the development of complex workover technology.

Field results on Chevron's HASDrive process are also exceeding forecasts, and many of the above comments regarding predictability and operability of the SAGD process could equally be applied to this test.

In total, the Phase A level tests have confirmed the ability of horizontal wells to cope with the Athabasca challenge. Below-fracture pressure steaming and gravity drainage can provide exceptional recovery with highly efficient steam use. Such technical results offer prospects of greatly improved economics and a highly competitive position in the heavy oil industry.

Organization

Because of adverse industry conditions at the time, AOSTRA took the initiative of acting as operator in the development of the UTF project. The challenge of maintaining a cooperative development program with industry has also been met.

Early in the project, industry representatives joined in a consultive steering committee to work with AOSTRA in process evaluation and the planning of the field tests. This helped ensure industry concurrence with the overall program as it evolved. Later on, as conditions improved, several of these companies became participants in the process testing phase of the development. AOSTRA will continue to act as operator during the pilot programs, but the stage is set for eventual transfer to an industry operator if the program moves to commercial scale.

As operator, AOSTRA has executed the project on a contract basis making full use of Alberta resources. It has been very much a local success; the new technology has been developed by Albertans and is readily available to Alberta industry.

Project Economics

Studies of the potential economics of commercial scale operations are an integral part of ongoing project development serving two major purposes. First, they support justification for continuing and expanding the pilot work. Pilot scale operation does not pay its way, so there must be an eventual commercial incentive to warrant the research and development investment. Second, these studies identify major capital/operating cost and value components to guide optimization of the design in the piloting stage.

To provide input to consideration of an enlarged Phase B pilot program, AOSTRA carried out economics studies last year incorporating the very promising results from the Phase A field test.[9]

Commercial plant scale was set at a nominal 1600 m^3/d (10,000 BPD) of bitumen production. This capacity is large enough to achieve most of the economies of scale in an in situ recovery operation. At the same time, it is a manageable size to fit the immediately available reserves and to minimize initial investment and risk in scale-up.

The operation was conceived as a major expansion from the planned Phase B test, thereby taking advantage of existing general facilities on the UTF site. Design and construction of the expansion would begin in 1994 to coincide with expected success on the Phase B long well pilot. Commercial operations would start in 1996 and achieve full capacity operation within two years. It was assumed that production would be pipelined out to North American markets.

Preliminary designs of mine extension, well development and process facilities were developed to provide a basis for estimates of capital and operating costs. The schedule of these expenditures constituted the cost stream side of the economics.

A forecast of bitumen value involved two steps. First, bitumen was priced relative to the current North American reference crude, West Texas Intermediate (WTI) at Chicago. Second, a forecast of WTI future pricing was obtained from the National Energy Board markets report of September, 1988. The bitumen price forecast derived from these sources, combined with the project production schedule, provided the revenue stream.

Two indicators were used as a measure of project viability: supply price and internal rate of return.

Supply price is the average cost of production over the life of the project taking into account the time-discounted values of expenditures and production. It is a particularly appropriate measure during project development since it highlights both the competitive position of the project compared with other supplies and the major opportunities for optimization within the project.

For the 1600 m^3/d expansion at the UTF, the estimated base case supply cost was \$68.30/m^3 of bitumen (under \$11.00/bbl). This is potentially attractive even in today's markets and should be quite competitive with other major sources of

Table 1

COMMERCIAL CONCEPT IN SITU PROJECTS
PRODUCTION COST COMPARISONS

	AOSTRA UTF		ESSO COLD LAKE		BP WOLF LAKE		SHELL PEACE RIVER	
	$/bbl	%	$/bbl	%	$/bbl	%	$/bbl	%
Surface Plant	1.61	15	1.72	15	2.67	12	2.04	15
Mining/Drilling	1.81	17	1.71	15	2.84	13	2.82	20
Additional Wells	1.03	9	2.27	20	6.63	30	1.48	10
Fuel ($2.50/GJ)	2.87	26	2.63	23	5.97	27	4.00	29
O&M	3.56	33	2.95	27	3.83	18	3.60	26
	10.88	100	11.28	100	21.94	100	13.86	100

bitumen supply. Table 1 has been drawn up from published information presented in a paper by S. Singh et al.[10] Corresponding figures from the UTF base case study have been added for comparison. It should be noted that the other projects referenced are developing resources which have been considered more tractable than the Athabasca region. Even allowing for some ambiguity in published data from differing sources, it seems apparent that the UTF expansion should be competitive with the best of other bitumen production in situ operations. Certainly, it would be outstanding for Athabasca.

Internal rate of return (IRR) is the common standard for measuring a project's bottom line, its profitability under expected market conditions. With the base case cost and revenue streams generated for the 1600 m^3/d expansion, the calculated IRR for the project was 29.7%. Sensitivity runs were made to check the impact of market price variables, with the results shown on Table 2.

The base case revenues were derived from the average forecast values in the referenced NEB report; the high bitumen and low bitumen cases represent the extremes of the NEB forecast. Since no operating assumptions were changed, the supply price remains the same in all cases. However, the expected rate or return is affected dramatically, with return varying from over 40% to less than 20% in response to bitumen price alone.

Fuel cost is generally a most significant component of the supply price in thermal recovery projects. The base case assumed a fuel gas cost of $2.50/GJ ($2.64/MMBTU), a cost which is expected to be a limit for gas set by substitute fuels. This assumption was raised to $3.00/GJ in the high gas case, with the indicated impact on supply price and rate of return. The relatively small effect of this 20% increase in fuel cost can be credited to the very efficient use of steam in the SAGD process.

Overall, the economics are most encouraging. With regard to industry position, the UTF expansion should be a highly competitive source of bitumen supply. With regard to eventual profitability, it offers prospects for a commercially viable operation under a wide range of expected market values.

FUTURE

From the work to this point, AOSTRA is convinced that further pilot development at the UTF is fully warranted. The Phase A performance and the supporting economics studies are very encouraging, and confidence in these prospects for commercial application would be greatly enhanced by the successful demonstration of Phase A performance at the long well Phase B level.

The Phase A level program now underway is scheduled to run until the end of March, 1990. A program to expand the operation to the Phase B pilot level has been developed in consultation with the project participants. It will be based on the testing of three pairs of wells, each 600 meters long with 500 meters of completion in the oil sands (Figure VII). These pilot pairs will be similar to the proposed commercial well pair design and will represent a

Table 2

PRICING SENSITIVITIES

	BASE CASE	HIGH BITUMEN	LOW BITUMEN	HIGH GAS
Supply Cost ($/m3)	68.60	68.60	68.60	72.36
Internal Rate of Return (%)	29.7	41.1	16.9	27.9

significant scale-up of the 60 meter completions employed in the Phase A test wells.

The proposed schedule for the Phase B-1 program is shown in Figure VIII. Work is proceeding on the surface drilling of observation and exploratory wells for completion within this winter's drilling window. Tunnel extension will start by the end of March, with underground drilling of the long horizontal wells scheduled to get underway this summer. The pilot wells and expanded underground process facilities should be in place early in 1991. Steaming will begin late that spring, and definitive results for the planning of any further expansion should be achieved by 1993.

Technology developed at the UTF will eventually have application well beyond the project itself. The near term future for the UTF technology is likely to be in the vast Athabasca oil sands which so far have defied profitable in situ recovery. In the long term, it appears that horizontal wells and gravity drainage processes could revolutionize in situ bitumen and heavy oil production, with substantial cost reductions compared to conventional cyclic steam stimulation technology. Such advances could bring the Alberta bitumen industry back into the realm of profitability, even under the competitive pricing regime currently facing the industry.

ACKNOWLEDGEMENTS

The authors wish to thank AOSTRA for permission to publish this paper. Participation in the UTF project by Amoco Canada Petroleum Company Ltd., Canada Centre for Mineral and Energy Technology (CANMET), Chevron Canada Resources Limited, Mobil Oil Canada, Petro-Canada Inc., Shell Canada Limited and Texaco Canada Limited is also recognized.

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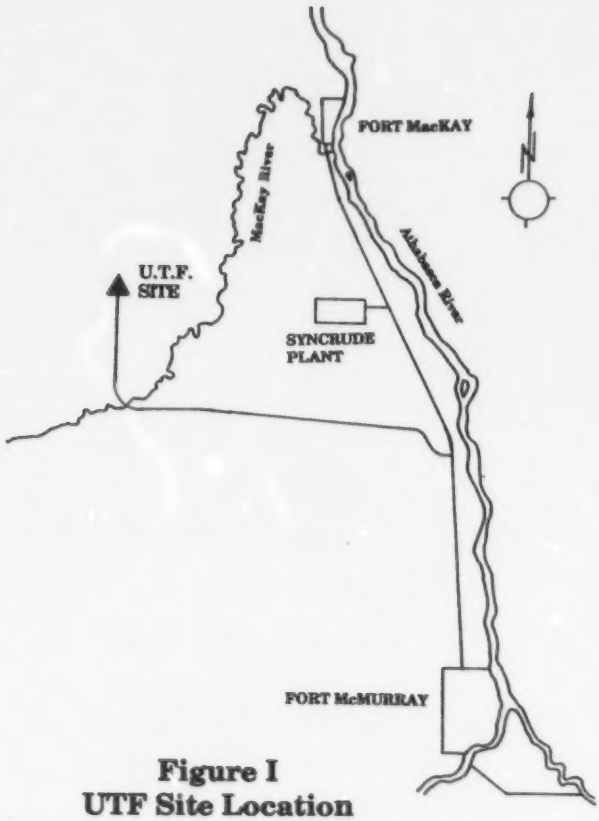

Figure I
UTF Site Location

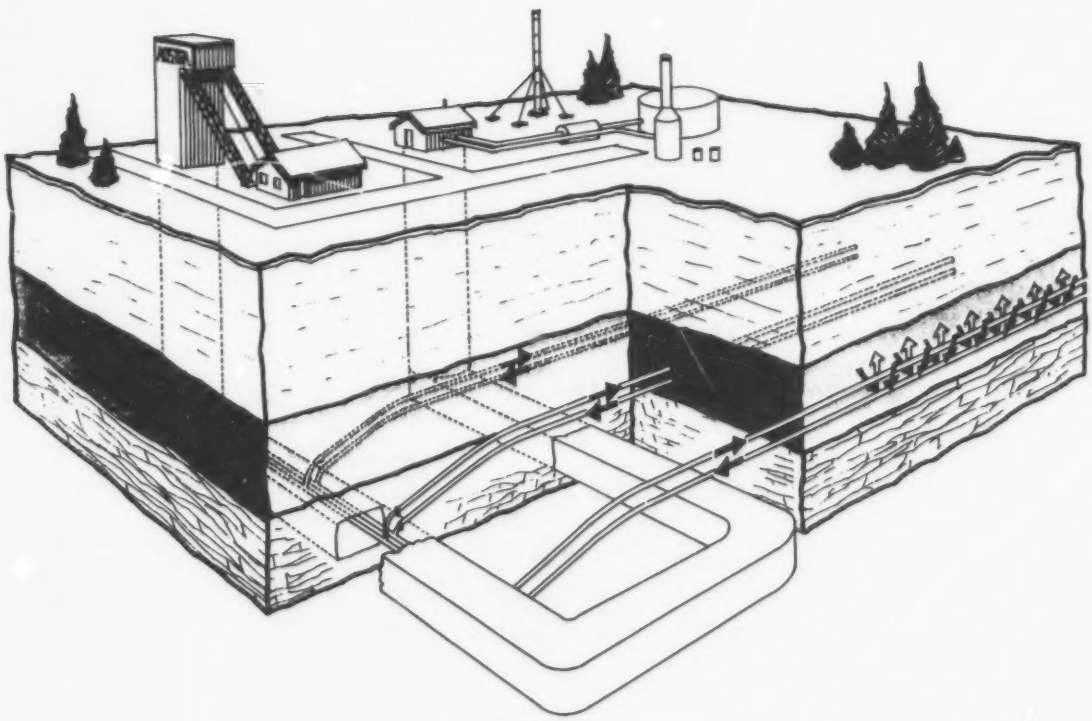

Figure II
Underground Test Facility

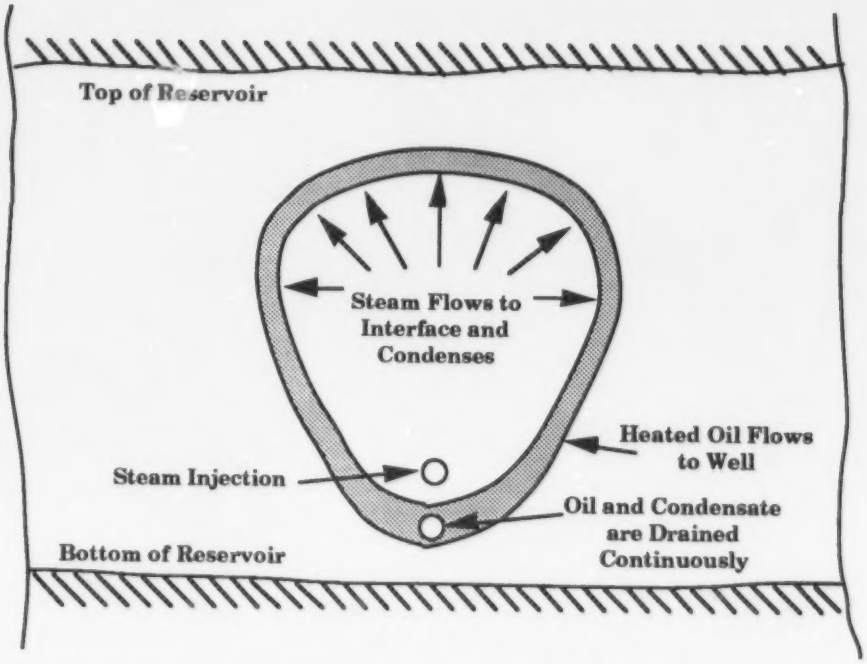
Top of Reservoir
Steam Flows to Interface and Condenses
Heated Oil Flows to Well
Steam Injection
Oil and Condensate are Drained Continuously
Bottom of Reservoir

Figure III
Gravity Drainage Process

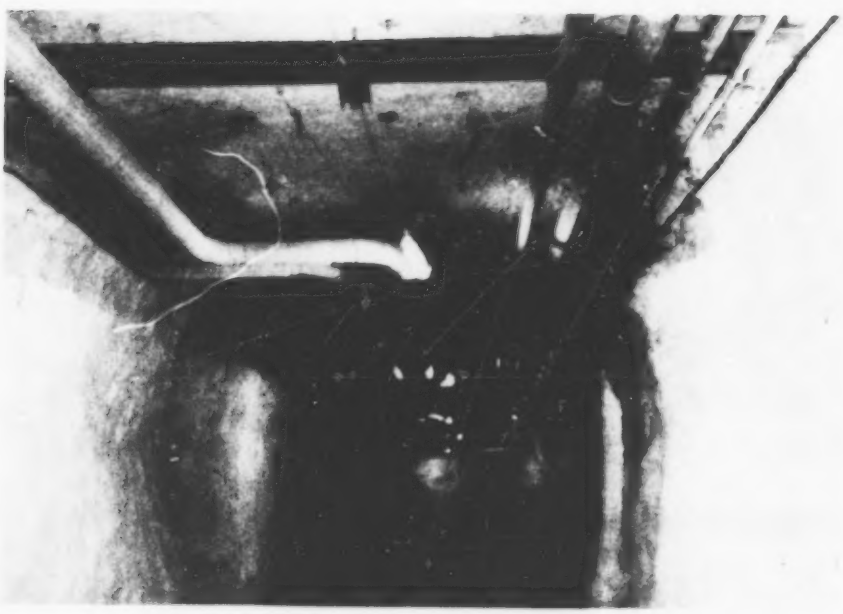

Figure IV
Typical Tunnel Run

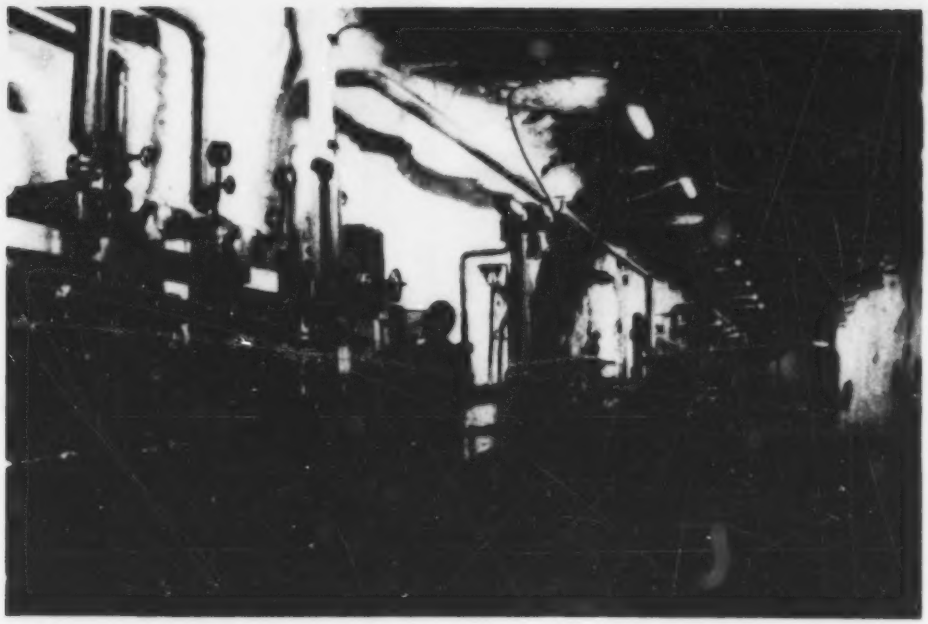

Figure V
Phase A Operating Chamber

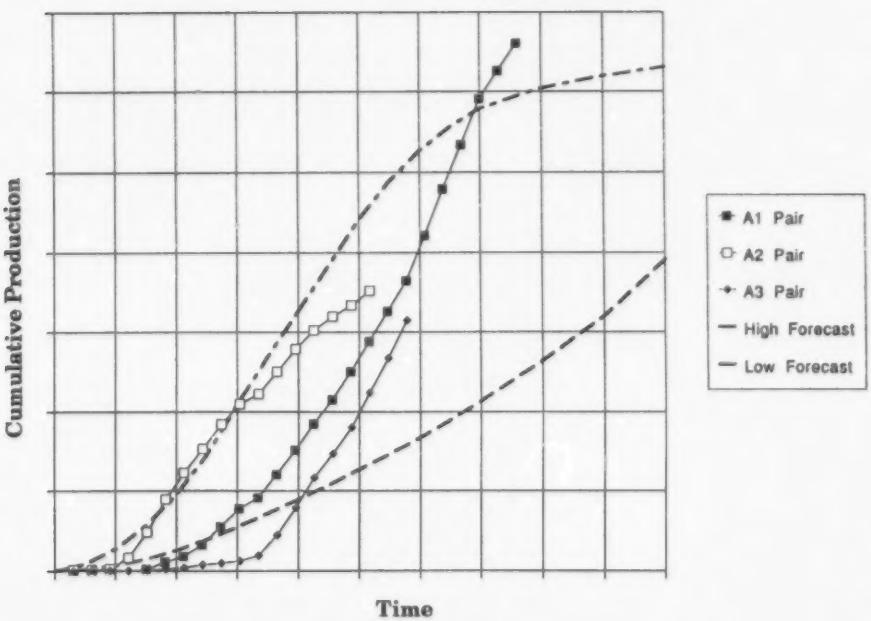

Figure VI
Phase A Performance: Actual vs Predicted

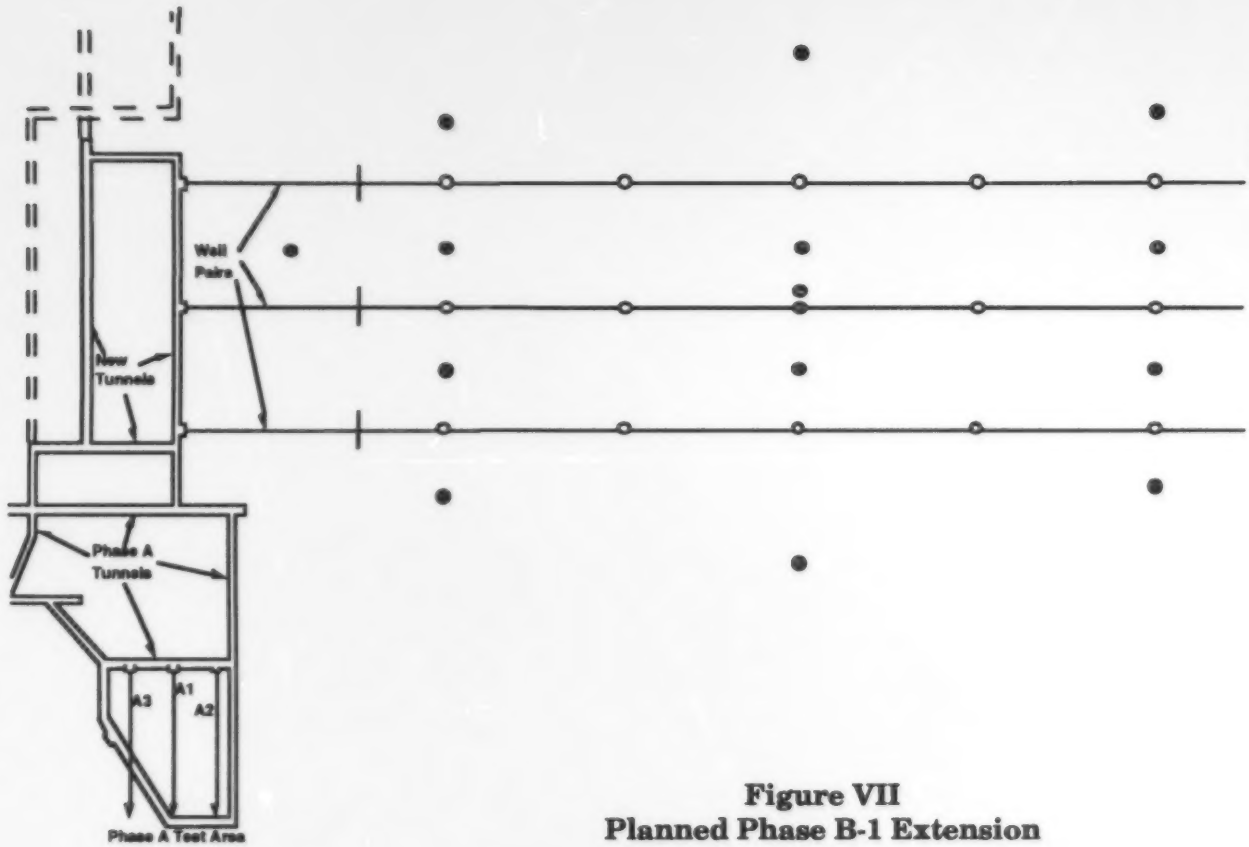

Figure VII
Planned Phase B-1 Extension

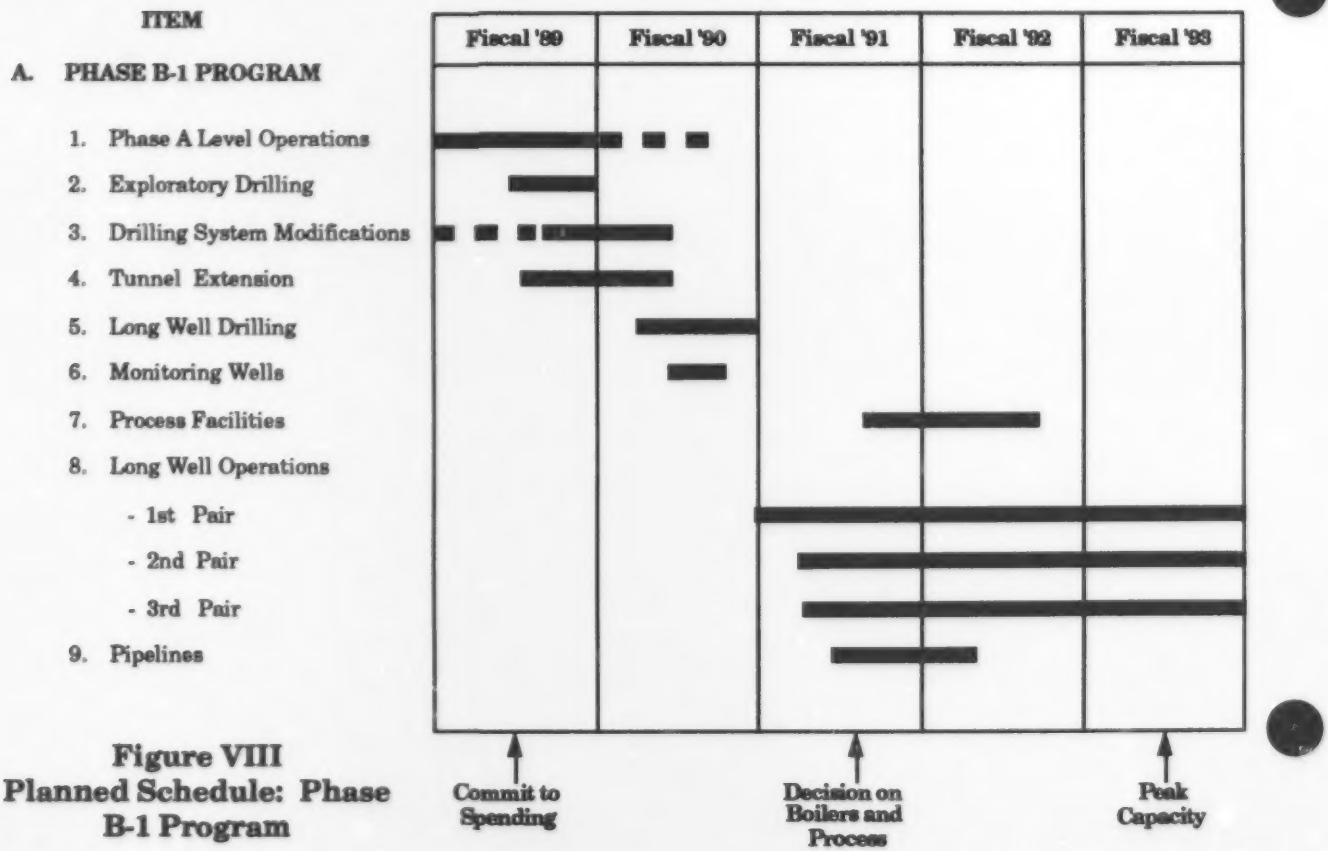

Figure VIII
Planned Schedule: Phase B-1 Program

The Use Of Horizontal Wells Drilled From The Surface For The Recovery Of Bitumen, Heavy Oil, Conventional Oil And Gas

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Abstract. Horizontal wells, because of their longer lengths of well in contact with the reservoir, can have much higher productivities than conventional vertical and near vertical wells. The economic advantage of this possibly improved performance must be balanced against the higher capital and operating costs of horizontal wells.

This paper discusses, in a quantitative manner, with illustrations, the effect of the important variables on the relative performance of horizontal wells. Some potential applications have great promise and some have very little.

While the paper will be general in its introduction, particular attention will be paid to the potential for horizontal wells for the recovery of bitumen and heavy oils and to the potential performance of SAGD and vertical steam flooding for typical Canadian conditions.

Mention will also be made of the possibility of using light vapourized solvents such as propane, together with hot water for the recovery of heavy oils and bitumen. This technique is called the S"Vapex" process.

The use of horizontal wells for the production of all forms of petroleum including heavy oil and bitumen is an area of considerable current activity, both in Canada and in the world in general. The number of horizontal wells in Canada is now approaching 50 and in the world as a whole is of the order of 500.

Typical horizontal wells are drilled, typically, from the surface with the well deviating so as to proceed approximately horizontally through the reservoir formation. The horizontal penetration of the reservoir can be very long; in many recent wells, it extends for approximately 500 metres and wells with 1000 metres of penetration are known (1,2).

The incentive for drilling horizontal wells is that they can have much greater lengths open to the reservoir and, consequently, their productivity can be higher than that found for conventional wells. Thus, although a horizontal well may cost considerably more than a conventional, near-vertical well, fewer wells are required to provide comparable drainage.

Horizontal and Vertical Well Systems with Comparable Drainage

Slide 2 shows the results of typical calculations for the drainage of a confined pattern assuming pseudo-steady state flow. In this diagram, the performance of a horizontal well which is 500 metres long and located within a rectangular drainage pattern of optimum shape is compared to that of vertical wells draining the same area (3).

The upper diagram shows a situation in which the horizontal well drains a pattern having an area of one section or 259 hectares. In this situation, the flow to the well is approximately radial and the system behaves as if there were a vertical well having a well bore radius equal to one quarter of the length of the horizontal well (i.e. 125 metres). Such a mammoth vertical well can drain an area which is 6 times larger than that which can be drained by individual conventional vertical wells.

The lower diagram shows the same horizontal well located in an optimally shaped rectangular drainage area of 10 hectares. This well would have the same productivity as 29 conventional wells located in the same area, i.e. the 10 hectare spacing for the horizontal well would be equivalent to a 0.34 ha or 0.9 acre spacing for vertical wells. In situations where very close spacing of vertical wells is desirable, horizontal wells have a much greater advantage. In these situations, a horizontal well can be looked on not just as a super-productive single vertical well, as in the upper diagram of Slide 2, but as a replacement for whole rows of vertical wells. In the lower diagram of Slide 2, the flow to the horizontal well is not radial as in the upper diagram, but tends to be linear with flow at right angles to the well.

Slide 3 shows the effect of well spacing upon the number of vertical wells which can be replaced by a single 500 metre horizontal well. When the vertical wells would normally be very closely spaced, then a horizontal well has a tremendous advantage.

Effect of Reservoir Thickness

In both Slides 2 and 3 it is assumed that the reservoir is relatively thin, i.e. that the horizontal well would have the same performance as an infinitely-conductive vertical fracture of the same length which extended from the top to the bottom of the reservoir. When the reservoir has appreciable thickness, then it is also necessary to allow for the vertical convergent flow to the horizontal well as shown in Slide 4. The formula in the middle of this slide gives the pressure difference between the well bore and a fairly remote point at a horizontal distance x. The right hand side of the equation contains two terms:

- the first corresponds to the linear pressure drop which would be present if the well were an infinitely-conductive fracture.
- the second term adds a pressure drop which corresponds to that required to cause the convergent flow into the well bore.

This pressure drop is a function of the thickness h of the reservoir and the well bore radius, R_w. This added pressure difference can also be thought of as being equivalent to an extra distance for flow Δx, as shown at the extreme right of the equation. Calculated values of Δx are shown at the bottom of the slide. For reservoirs of height 3 m, this extra distance is only 1.5 m but it increases as h increases and for a reservoir 100 m thick, the extra distance would be 161 m. The advantage of horizontal wells is less in thick reservoirs, at least when the flow pattern is of the general type shown in slide 4. This qualification is important because, in many cases, even in thick reservoirs, horizontal wells are used to avoid coning of water or gas or both. In these instances, vertical flow is required whether the well is vertical or horizontal since vertical wells will be only partially completed through the thickness of the reservoir.

Effect of k_v/k_h

Increasing the ratio of the horizontal permeability to the vertical permeability has a similar effect to that of increasing the reservoir thickness h. This effect can be allowed for by substituting an effective reservoir thickness h^* for h in the equation of Slide 4; this is given by the equation in Slide 5. Thus, for example, if k_h/k_v were equal to 9, the effective thickness of the reservoir would be the square root of 9 or 3 times the actual thickness.

In the lower part of slide 5, the number of vertical wells which could be replaced by a horizontal well with a spacing of 10 ha per 500 m horizontal well in a reservoir of thickness 30 m is shown. It is shown in Slide 2 that for a thin reservoir, 29 wells could be replaced. In a reservoir 30 m thick with equal horizontal and vertical permeabilities, only 13 wells could be replaced. If k_h/k_v were 100, this would drop to 8.7 wells. Nevertheless, there is still a very large advantage when a spacing of this order is required.

Directional Horizontal Permeability

Another important effect of varying permeabilities occurs when the horizontal permeability is different in one direction from another. Slide 6 compares the drainage patterns which might be found with conventional wells for a ratio of 16:1 in the horizontal permeabilities with those for a situation where the ratio is 1. The drainage to the conventional wells reaches farther out in the direction of higher permeability. This means that for optimum pattern shapes, the vertical wells should drain long, rectangular patterns. For this reason, a horizontal well located so that it lies in the direction of low permeability will replace a larger number of vertical wells than it would in a homogeneous reservoir. An extreme example of this situation occurs when there are multiple natural fractures within the reservoir which lie parallel to each other. These provide much greater effective permeability in the direction of their length than in the normal direction. A horizontal well can penetrate many fractures whereas a vertical would penetrate only a few at most. Factors such as this make horizontal wells very effective in naturally fractured reservoirs. Particularly successful applications have been in the Italian offshore Rospo Mare field (4,5), the Austin Chalk in Texas (6), and more recently in the Midale field in Saskatchewan (7).

Artificial Fractures

In many cases, the production from a conventional vertical well can be increased greatly by creating a vertical fracture from it. The diagram in the top of Slide 7 shows such an arrangement. Where vertical fractures are very effective, they perform very similarly to a horizontal well. In these cases, it may often be that the vertical fracture is the more economic solution. However, in many situations, it is not practical, or even possible, to make vertical fractures of the length of a horizontal well and of the conductivity of a horizontal well. Depending upon the tectonic stresses, vertical fractures may tend to wander vertically away from the reservoir rather than to penetrate it horizontally. However, where vertical fractures are successful and economic, it may very well be that they can provide a more economic solution than horizontal wells.

It is possible to create multiple artificial fractures along the length of a horizontal well as shown in the lower diagram in Figure 7 (8). Ideally these should be located normal to the well and this can be done if the well is located in the direction of the least principle compressive stress. However, particularly when horizontal wells are drilled radially from an offshore platform, like spokes in a wheel, they may have to be located in non-optimal directions.

Creating multiple fractures along a horizontal well is an expensive process and doubt has been expressed as to whether this is an economic procedure. With offshore locations where the cost of the platform area assigned to a well (the slot) can be several millions of dollars, horizontal wells with multiple fractures can be economic because of their greater productivity. For onshore applications, there is more doubt, although, if a horizontal well is drilled and found to be of low productivity, then its stimulation by fracturing may be an economic means for recovering the costs which have already been spent.

Coning Situations

Horizontal wells can have particular value in reservoirs where the coning of water from below or gas from above is an important factor. In these situations, vertical wells are usually completed over a small horizon with the object of eliminating, or at least minimizing, the coning effect (slide 8). In some cases, operation below the critical rate at which water or gas is drawn into the well may be feasible; in others, this rate may be too low to be economic. In cases where operation below the critical rate is economically feasible, then there may be great advantage from using horizontal wells because they will allow production at much greater rates (9).

The same is also true, in principle, for cases where operation at rates above the critical is necessary for economic reasons. In this case, if the reservoir has uniform properties along the length of the horizontal well, then a higher production rate and a higher cumulative production for the well should be possible for the same produced water/oil ratio. However, the situation may arise where there is a region of higher overall permeability, or worse, higher vertical permeability, along the length of the vertical well and this section of the well may produce excessive water or gas production (slide 9). Thus, although the horizontal well may have replaced a whole row of vertical ones, it lacks flexibility. Whereas a single high water production vertical well can be shut in, the problem is much more complicated with a horizontal well. This situation is exacerbated if the horizontal well is completed with a simple slotted liner completion in an open hole. In these cases, well control by, for example, squeeze cementing sections is impracticable. One way around this problem which has been used recently is to set cement-inflated packers at intervals along the length of the horizontal well when it is completed initially so that it may be subsequently controlled in sections. Complete cementing of the horizontal section followed by conventional perforation has also been used.

Factors Favouring Horizontal Wells

Slide 10 summarizes the important factors which favour horizontal wells in general. These are the requirement for relatively close spacing, thin reservoirs or, if they are thick, reservoirs where coning is a problem, and reservoirs having high directional horizontal permeability such as is created by parallel, natural vertical fractures.

Heavy Oil and Bitumen

Up until now, we have been considering horizontal wells in general, but the conclusions which have been drawn are also relevant to thermal projects. Slide 11 is a modified version of slide 10 where the comments in italics refer to steam recovery processes. A close spacing requirement is characteristic of thermal recovery; for example, in California, well spacings as small as 5/8 acre (1/4 ha) have been used.

The main problem in steamflooding is that of steam overriding the reservoir, breaking through to the production well and bypassing. This is a special coning problem and can be overcome by using horizontal wells.

Although most of the heavy oil reservoirs which have been produced so far consist of unconsolidated sandwhere natural fractures do not play a role, there are, in Alberta, enormous deposits of bitumen in the Carbonate Triangle and much of this carbonate rock is fractured; one would expect that horizontal wells will play an important role here. These reservoirs have very high natural permeabilities because of the fracturing and there would seem to be desirable applications for the use of horizontal wells, perhaps using steam recovery, or perhaps using the promising propane vapour approach which we described recently (10).

Gravity Drainage

The production of heavy oil or bitumen by the steam-assisted gravity process is shown in slide 12. Steam is injected into the reservoir and a steam chamber grows around the injector. Steam flows to the perimeter of the chamber, heats the oil and makes it mobile; the mobilized oil drains, driven by gravity, to the horizontal producer located at the base of the reservoir. The process can be viewed as a steamflood with the withdrawal of oil controlled so

that steam does not cone to the production well. It has been demonstrated theoretically, in scaled models in the laboratory, and in successful field tests that economic drainage rates can be achieved at the producer without appreciable steam bypassing [11-16]. The process can be used efficiently even where bottom water is present [17].

This same approach is also possible using propane vapour together with some heat, as was described recently [10].

Horizontal Spacing Between Horizontal Wells

An important consideration in the commercial development of steam-assisted gravity drainage is the spacing between the horizontal wells (Slide 13). A closer well spacing results in more investment for wells but has the advantages of faster production and depletion, a shorter project life, less heat loss per barrel of oil produced and a higher oil/steam ratio. There is an economic optimum spacing for any particular situation. In some cases where drainage is relatively slow, the optimum spacing will be very close and in these cases, mine-based wells may be the economic way to go.

Situations where this could be the case might be in shallow, deposits of very viscous bitumen where high temperature steam is not practicable because of containment problems. Another case might be in reservoirs having relatively large heat capacities (eg. low-porosity carbonates). Although having high heat capacities, these reservoirs, if they are karstic, such as the Grosmont, probably have relatively high permeabilities which will allow economic production. A particularly attractive possibility in such situations is the use of propane vapour with horizontal wells because of the minimal heat requirements [10].

Slide 14 illustrates, using a quantitative example, the factors which determine the required well spacing. In this case, it is assumed that horizontal wells having a length of 500 metres are used and that an oil drainage rate between 0.02 and 0.2 m^3 per metre of horizontal length per day is practicable. This is the range in which one might expect the average rate to fall in practical cases. This oil rate will thus give a total rate of 10-100 m^3/day of oil per well.

It is assumed that the reservoir is 30 m thick and that there will be an oil recovery of 50% with a project life of 10 years. Using these parameters it is calculated that the oil recovery per hectare would be 43,575 m^3 and that the cumulative oil production per well during the life of the project would be 36,500 - 365,000 m^3. Using these two numbers, one estimates that the area that would be drained per horizontal well would be between 0.8 and 8 hectares. This would result in a horizontal well spacing between 16 and 160 metres. It is doubtful whether tunnel-based projects are economically feasible at the upper end of this range. However, at the lower end of the range they may be quite competitive. One would expect that the new propane-vapour process would tend to give drainage rates near the lower end. It is possible that, for some reservoir situations, a mine-based facility might be attractive for this process.

Closely Spaced Wells

One of the concerns which we had several years ago when considering the use of closely spaced horizontal wells was whether rising steam chambers from such wells will result in a decreased rate of production when they intermingle [19]. It has been found that this is not the case [16]. Slide 15 shows the isotherms obtained in a high-pressure, scaled-model experiment around steam chambers rising from 5 parallel horizontal wells which are closely spaced. These chambers intermingled before they reached the upper boundary of the reservoir. However, as may be seen from Slide 16, the oil production rate from individual wells was no lower in the experiment with the closest well spacing and may in fact have been somewhat higher. These data are extrapolated to the case of the conditions at the Underground Test Facility in Slide 17.

Conclusions

The overall conclusions which may be drawn from the material presented in this paper are given in Slide 18. This lists the positive and negative factors which would influence the choice of horizontal wells over vertical ones. Horizontal wells have advantages when the conventional wells would normally be closely spaced. They have advantages when there is coning and where production below the critical rate is practical. They have very substantial advantages in reservoirs containing vertical fracture systems which can be penetrated by a horizontal well but which would be hard to contact with vertical ones. They have advantages in offshore situations because the higher well productivity is reflected in a lower platform cost. Negative factors, but not necessarily prohibiting ones, include cases where fractured vertical wells give high economic production rates, cases where coning is not important and at the same time the reservoir is thick or the ratio of k_h/k_v is large. In cases where there is an economic need to operate the production well above the critical coning rate, the choice of horizontal wells may be dubious if there is concern that the properties of the reservoir vary greatly along the length of the projected wells.

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SLIDE 1

THE USE OF HORIZONTAL WELLS FOR THE RECOVERY OF BITUMEN, HEAVY OIL, CONVENTIONAL OIL, AND GAS

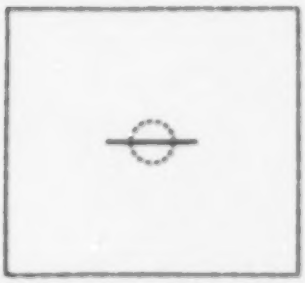
by

Roger M. Butler

University of Calgary

SLIDE 2

REPLACEMENT OF VERTICAL WELLS BY HORIZONTAL WELL



Drainage area 1634 x 1536 m

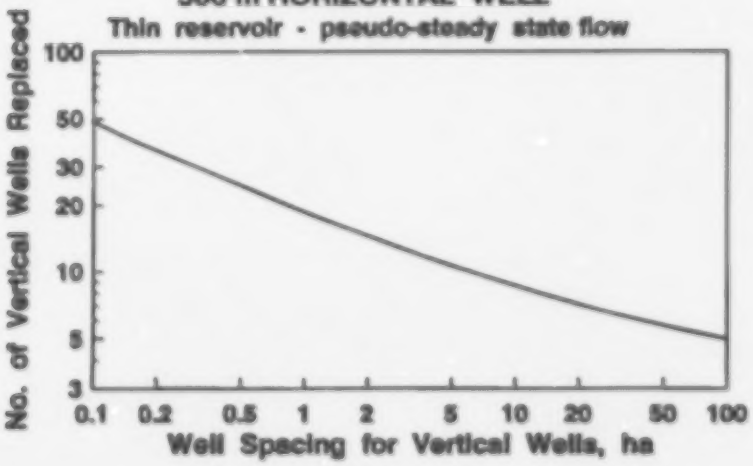
Drainage area 592 x 170 m

Well Length	Drainage Area	Vertical Wells
500 m	259 ha or 1 section	6 *107 acres per well*
500 m	10 ha	29 *0.9 acre per well*

SLIDE 3

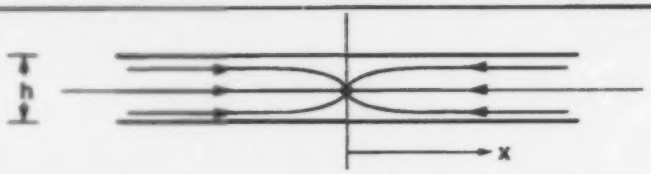
NUMBER OF VERTICAL WELLS REPLACED PER 500 m HORIZONTAL WELL

Thin reservoir - pseudo-steady state flow



SLIDE 4

CONVERGENT FLOW TO HORIZONTAL WELL



$$\Delta P = \frac{q\mu}{2k_v L h}\left[x + \frac{h}{\pi} Ln\left[\frac{h}{2\pi R_w}\right]\right] = \frac{q\mu}{2k_v L h}[x + \Delta x]$$

Values of Δx for $R_w = 0.1$ m

h (metres):	3	10	30	100
Δx (metres):	1.5	9	37	161

SLIDE 5

EFFECT OF VERTICAL PERMEABILITY

Increasing the ratio k_h/k_v has an effect similar to that of increasing the reservoir thickness, h.

$$h^* = h\sqrt{k_h/k_v}$$

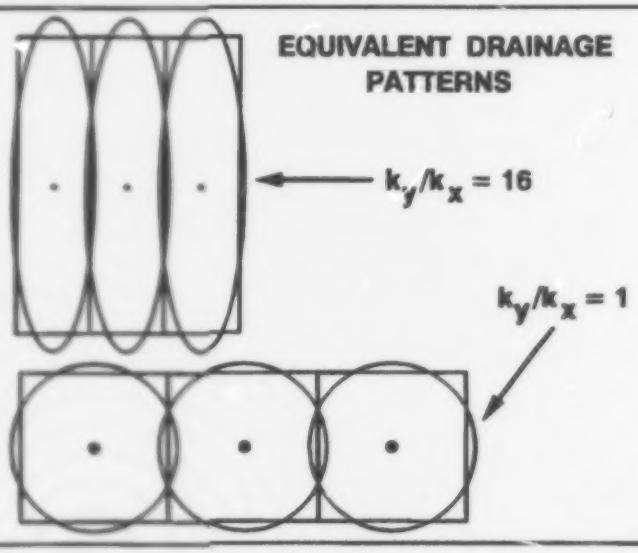
Effect of k_h/k_v on Number of Vertical Wells Replaced per Horizontal Well

Area per H. Well = 10 ha; Hwell length = 500 m; h = 30 m

k_h/k_v	1	10	100
No. of Vertical Wells Replaced per H. Well	13.3	10.7	8.7

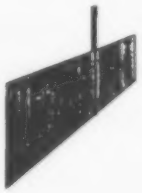
SLIDE 6

EQUIVALENT DRAINAGE PATTERNS



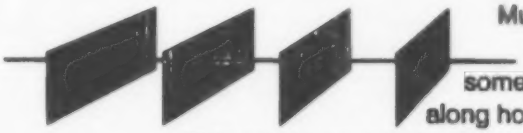
SLIDE 7

ARTIFICIAL FRACTURES



A vertical well with a fracture is similar to a horizontal well.

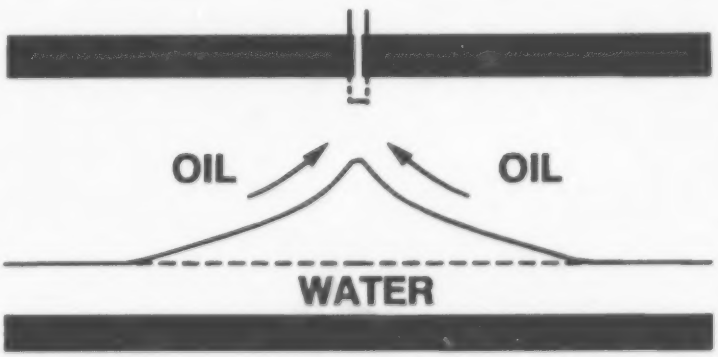
In areas where vertical fractures are successful and economic this combination may be better than a horizontal well.



Multiple artificial fractures are sometimes created along horizontal wells. This can be economic, particularly offshore.

SLIDE 8

CONING



SLIDE 9

EFFECT OF REGIONS OF HIGH k_v ON CONING

- If the production rate is less than the critical then a region of high k_v/k_h is beneficial.
- However, if the production rate has to be maintained greater than the critical in order for the operation to be economic, then regions of high k_v/k_h can give early and excessive water/gas production.

SLIDE 10

IMPORTANT FACTORS FAVOURING HORIZONTAL WELLS

Close spacing requirement

Thin reservoirs or coning problem

Natural vertical fractures

SLIDE 11

IMPORTANT FACTORS FAVOURING HORIZONTAL WELLS
for thermal recovery

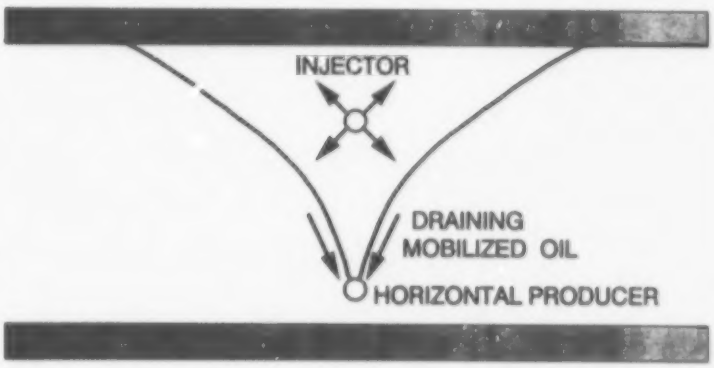
Close spacing requirement
Spacings as low as 0.25 ha are used in thermal recovery.

Thin reservoirs or coning problem
Steam coning is the main problem in steamflooding.
It is the reason why close spacing is adopted.

Natural vertical fractures
Very high permeability fractures and cavities are common in Alberta Carbonate Triangle (e.g. Grosmont).

SLIDE 12

GRAVITY DRAINAGE FROM CHAMBER PERIMETER



SLIDE 13

HORIZONTAL SPACING BETWEEN WELLS FOR SAGD

- Closer spacing results in:
  - More well investment
  - Faster production and depletion
  - Shorter project life
  - Less heat loss per barrel produced
  - Higher Oil/Steam Ratio
- There is an economic optimum spacing
- Mine-based wells might be economic if very close spacing is required.

SLIDE 14

SAGD WELL SPACING - BALLPARK ESTIMATES

Assume:

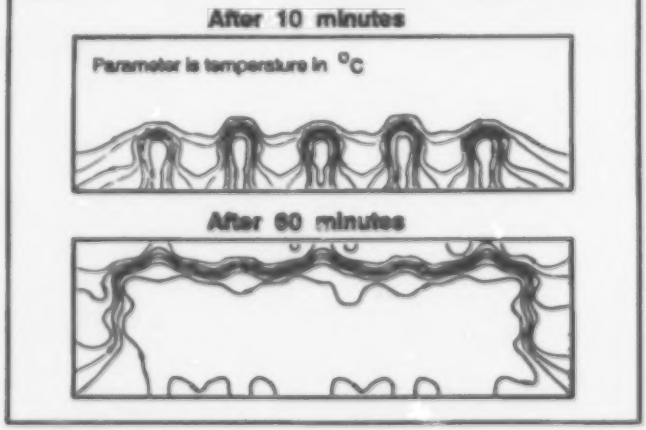
Well length	500 m
Average oil rate	0.02-0.2 m^3 /m d (10-100 m^3/d)
Reservoir thickness	*30 m*
Oil recovery	50 %
Project life	10 yr (3650 d)

Parameters calculated from above:

Oil production per ha	43,575 m^3
Cumulative oil per well	36,500 to 365,000 m^3
Drainage area per well	0.8 to 8 ha
Required well spacing	16 to 160 m

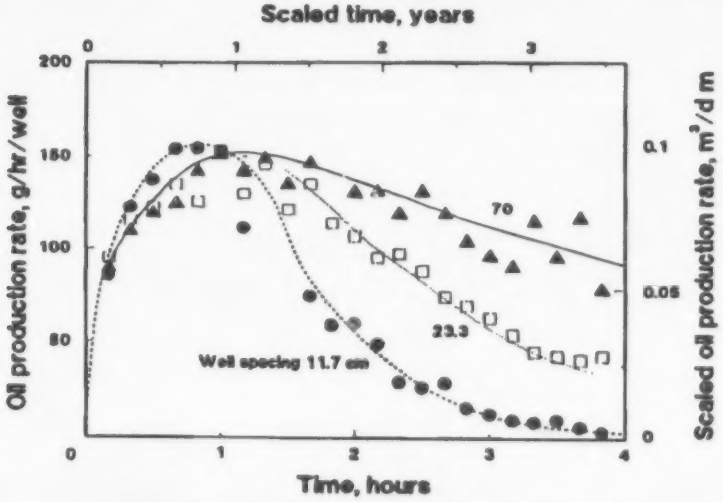
SLIDE 15

STEAM CHAMBERS RISING IN SCALED MODEL RISING ABOVE 5 CLOSELY-SPACED WELLS



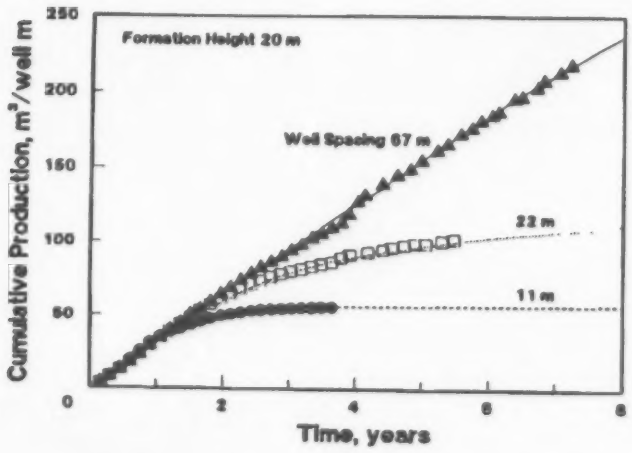
EFFECT OF WELL SPACING ON RATE

SLIDE 16



EXTRAPOLATION TO UTF

SLIDE 17



SLIDE 18

TECHNICAL FACTORS AFFECTING CHOICE OF HORIZONTAL OR VERTICAL WELLS

POSITIVE:

- Need for close spacing of vertical wells
- Coning situations where production below critical rate is practical
- Reservoirs with vertical fractures, karsts etc.
- Offshore situations

NEGATIVE:

- Fracturing vertical wells gives high, economic production rate
- Coning is not important and h or k_h/k_v are large
- Economic need to operate above critical coning rate

Session 3

Paper no. 9

Advances Made In The Borehole Hydraulic Mining Technology For Oilsands

R. Paul, Senior Engineering Specialist, Esso Resources Canada Limited, and M. To, Senior Engineer, Esso Resources Canada Limited, The OSLO Consortium

Advances Made In The Borehole Hydraulic Mining Technology For Oilsands

R. Paul, Senior Engineering Specialist, Esso Resources Canada Limited, and M. To, Senior Engineer, Esso Resources Canada Limited, The OSLO Consortium

Abstract. The OSLO leases in the Athabasca area contain about 17 billion barrels of bitumen resource in place that is too deep for open pit mining and too shallow for steam based recovery techniques. The OSLO joint venture (Alberta Oilsands Equity, Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited, Gulf Canada Resources Limited, Pan Canadian Petroleum Ltd. and Petro-Canada Inc.) identified Borehole Hydraulic Mining technology as having the potential for recovering this resource.

Since 1984 considerable innovations in the critical aspects of the technology have been realized which has made the borehole mining technology potentially economic. These aspects are the mining tool design, cavity stability and the invention of a synergistic bitumen extraction process called OCWE (OSLO Cold Water Extraction). To prove up the technology, the OSLO joint venture and Alberta Oilsands Technology and Research Authority plans a field pilot in 1992.

INTRODUCTION

The OSLO joint venture holds six oilsands leases that contain about 17 billion barrels of *in-situ* bitumen resource which lies at depths between 50m to 150m. This resource cannot be recovered economically by the surface mining techniques and other known techniques such as conventional underground oilsands mining techniques, steam based *in-situ* bitumen extraction technology and electrical heating, etc.

In 1984, OSLO owners started investigating new technology in order to recover this resource and identified a borehole mining in situ cell process as the prime candidate. This technology was conceptually developed by Canadian Occidental, an OSLO owner, in the early eighties but was not tested in the field. OSLO's evaluation of this process indicated that the technology may have the potential to become economical if advances could be made in certain critical aspects. To reduce production costs, such areas as the mining tool design, a synergistic bitumen extraction process, cavity stability and the cavity backfilling technology would need improvement.

Further investigations indicated that advances in these aspects were possible and OSLO owners continued with further sustained development of the technology.

This paper includes the advances made in the borehole mining technology to date and describes the future plans to prove up the technology. The technology will not only make OSLO's substantial resource available, but will unlock vast Athabasca bitumen resources for the whole industry.

BACKGROUND

The following technology developmental steps have been undertaken:

- 1983 - CANOXY, an OSLO owner offered their "Cell Process" to the OSLO joint venture for evaluation. They had developed this especially for the Athabasca shallow resource during the 1979-1982 period.
- 1984 - A feasibility study indicated that the "Cell Process" as visualized by CANOXY will not be economical (cost $28/bbl bitumen) unless oil prices increased. The Cell Process used borehole hydraulic mining techniques and removed about 30% of the oilsand to the surface to create an initial void (figure 1). The produced oilsand would be processed at surface using the hot water extraction process. The remaining 70% of oilsands was mined in 0.3-0.5 metre slices and each slice was then processed in the cavity, using chemicals and steam to raise the temperature in the cavity to 80°C. The froth that

floated was pumped to surface (figure 2). This procedure was carried out until the whole cavity was mined out. Thus, 70% of the spent sands were left in the cavity. The cavity was backfilled and closed at the end of the mining process. The cavity stability during the operation was achieved by pressurizing the cavity with a gas.

An alternative case to the Cell Process that was also studied was the borehole mining scheme which removed all the oilsand to surface for processing, and then reinjecting the tailings and sealing the cavity. This "Full Pump Out" alternative was less costly ($23/bbl bitumen) than the Cell Process.

- 1985 – A feasibility study for 1500 m^3/day bitumen project was carried out assuming "Full Pump Out" and using a lower temperature extraction process that was developed by Imperial Oil in the early 1960's. This process mills the oilsands at 20°C in a tumbler and agglomerates the bitumen particles which are then screened off for further processing. The costs/bbl bitumen was reduced to about $21/bbl with this technology and project size.

  As well, during 1984/85, AGRICO mining company in Florida carried out a full pilot on their phosphate ore body. They made four experimental cavities and produced phosphate by using the borehole mining full pump out method.
- The OSLO winter bore hole drilling program included some tests to assist the borehole mining study. The in situ stress conditions of the oilsands were determined and the horizontal and vertical stresses were about equal at 50m to 150 m depth range. Also, the concept of maintaining a gas pressure on the oilsands to maintain roof stability was tested and it was found that gas leakage could be a problem with this idea.

  The alternative cavity support system is to use the hydraulic head, as was demonstrated by AGRICO in their Florida experiments. They also found that a slurry density of 30% solids was possible, instead of the 15% assumed in the OSLO study.

  OSLO's research on new extraction methods also had a breakthrough this year with the OCWE process (OSLO Cold Water Extraction)) being invented. A revision of the feasibility study was carried out, assuming a cutting rate of 100 tonnes/hour, injecting 2000 gpm at 14 MPa, using the OCWE process and the hydraulic head support system. These changes resulted in the operating costs being $16/bbl.
- 1988 – A four year development plan to prove the feasibility of the borehole mining process for oilsands was prepared that would result in a field pilot producing bitumen from borehole mining cavities in 1990/91. AOSTRA joined OSLO to assist in the development this year and have continued as a joint developer since. As underwater jetting required the jet nozzle to be close to the oilsand face, a new borehole mining tool was designed that allowed the nozzle pressure to operate at 3.5 MPa instead of the 14 MPa earlier. This new invention (patent pending) was model tested on a 1/4 scale in the laboratory.

  A field test of hydraulic jetting of in situ oilsand was carried out in a surface test pit at an OSLO pilot on Lease 41, north of Fort McMurray. The nozzle was fitted into a curved pipe that was supported on a steel frame and held using a backhoe . The high pressure pumping system was supplied by Schlumberger. Prior to going to the field, a series of calibration tests of jetting pressures were carried out at Esso Resources wave basin at the Calgary laboratory. These jetting tests were carried out in air and underwater to determine the pressures at the target under various nozzle sizes, pressures and stand-off distances. Once this information was known, the equipment was moved to the field where small pits (5m x 5m x 3m) were dug in oil sand and the water jet cutting efficiency was tested both in air and underwater. The results indicated that about 840 KPa (120 psi) pressure is required to cut the oilsand in air, whereas only 112 KPa (16 psi) is required to cut the oilsand underwater (1).
- 1989 – Last year's program included the following:(2)
  - Purchase of the borehole mining system from Union Pacific Resources of Colorado (figure 3). To our knowledge, this is the most advanced tool built in North America.
  - Field test program at Lease 41 included water jet cutting efficiency using the mining tool and pump equipment of the borehole mining system. The tests were conducted in small pits. The 1988 results were confirmed.
  - Development of a computer model for the borehole mining system was started.
  - An improved version of a 1/4 scale model of bringing the nozzle close to the oilsand face was built and tested. The tests indicated that the design is feasible.
  - A 4800 m^3/day bitumen feasibility study was carried out that indicated operating cost is $9.50/bbl of bitumen, and that project life costs per barrel ((capital + operating)/total barrels produced) could be reduced to about $12/bbl (3).

BOREHOLE MINING SYSTEM FOR THE OILSANDS

Borehole hydraulic mining has been tested the World over since 197[illegible] in the mining of various types of minerals such as coal, uranium, gold, phosphate and oilsands. A schematic of a borehole mining system similar to OSLO's is shown in figure 3. The

scheme includes drilling a 500-625 mm diameter borehole to the bottom of the oilsands and possibly setting casing if required. The borehole mining tool equipped with a high pressure water jet is then lowered into the borehole. The water jet cuts a circular cavity by revolving the tool string. The cut material is pumped to surface through the production pipe via a pump located at the bottom of the string. To keep the equipment manageable, two trailers are used; one a mining trailer and the other a pump trailer.

Initially about 25% of the oilsands are pumped out to the surface to create an initial void. This void provides room for the mining tool operation and for the swell of the remaining 75% of the sands that will be mined but not removed to surface. This is possible as when the water jet hits the oilsands, the oilsands disintegrate and the bitumen goes into the water phase whereas the clean sands drop to the bottom of the cavity. In a continuous operation a cavity is mined only if the adjacent cavities are either mined out or backfilled. Figure 4 shows the sequence of the mining of cavities in a continuous operation.

The geotechnical and geological conditions of an individual ore body will dictate the minimum pillars required to be left between cavities, but in general it would not be expected that a cavity would be mined out until adjacent cavities had been filled and sealed. That is, at the end of the operation of a cavity, the sand in the cavity is left to drain into a "sump" hole installed through the drill hole and the spent sands, from which the water is pumped out and the sand is left to consolidate. This drainage of the sands may take up to 3 months at which time the cavity is topped off with more sand and the drill hole is then closed.

TECHNOLOGICAL ADVANCES MADE TO DATE

A number of critical aspects of the borehole mining technology have been investigated since 1984 and innovative advances have been made which have reduced the costs of this technology rendering it economic. These critical aspects are as follows:

- Mining Tool Design
- OCWE process development and its synergy with the borehole mining slurry
- Cavity stability

The following aspects have been studied to date:

Water Jet Cutting Pressure. The previous test work for cutting the oilsands by a water jet was carried out by a CANMET/ AOSTRA/ University of Alberta joint program in 1979 and by Syncrude in 1984 (4,5). The U of A tests included mounting a jet nozzle on mobile equipment and shooting a high pressure jet onto the side of an escarpment where oilsands were exposed. Laboratory and field piercing tests were also conducted on water jet penetration of oilsands (6). Based on laboratory test results, a minimum jet impingement pressure of 1.2 MPa (170 psi) was found for the in air tests. The oilsands cutting rate was calculated at 65 tonnes/hour for slot cutting and 100 tonnes/hour for cutting at a face with free boundaries, such as cutting in the roof of a cavity. This production rate confirmed the assumption made in the feasibility study.

The Lease 41 set-up included a nozzle mounted on a frame which was then mounted on a backhoe. The high pressure water was provided by a contractor's pump truck. The water was re-circulated through a water reservoir as shown in figure 5.

OCWE (OSLO Cold Water Extraction) Process Development. The OCWE process, which is a pneumatic flotation process, was invented in 1986 and has been under development since then. The process uses air bubbles and chemicals and has good synergism with hydraulically produced slurries such as those from borehole mining and dredging. The process gives bitumen recoveries above 90%, at ambient temperatures, and for oilsands grades as low as 3% bitumen. The detailed information about the process has been included in the paper "Dredging and Cold Water Extraction Process for Oilsands" by W Jazrawi presented at this conference.

In the borehole mining system the scheme visualized to include the OCWE process is as follows:

The oilsands, being water wet, when impinged on and disintegrated by a water jet, release the bitumen from the oilsands fabric into a water medium. The specific gravity of bitumen is about equal to water, resulting in the bitumen and water forming a mixture, whereas the heavier sand drops down to the bottom. The present scheme takes advantage of this property. Originally we assumed about 30% of the oilsands would be pumped to the surface, the rest being processed inside the cavity i.e. only the bitumen and water mixture is pumped to the surface and the spent sands are left in the cavity. A recent study suggests that a much smaller percentage of the oilsand will need to be pumped out for this process to work. The bitumen is recovered by the OCWE process at the surface. This system is much simpler to handle and reduces the bitumen production costs substantially.

The Cavity Stability. This is the most critical area and considerable efforts have been spent in understanding the cavity stability problems and ways to economically control it.

The 1986 field program included determining the *in-situ* stresses for about 50-100 m depths at Lease 31. The hydraulic fracturing method was used that indicated that the ratio between the vertical and horizontal stress is about 1. The tests for using gas

pressure to support the cavity were also carried out that indicated that the cavity support by gas pressure may not be feasible as the gas kept leaking into the strata and required pressures could not be achieved.

The alternative scheme to support the cavity is to use an hydraulic head i.e. by filling the cavity with water up to the surface and connecting it to a large water source to provide a consistent head. A system like this was tested by the AGRICO mining company in Florida which successfully kept the cavities open during the operation of the cavity. This system has added advantages in cost reduction as the pumping operation from the cavity uses less horsepower as compared to the air supported cavity due to the hydraulic head and the water jet pressure required to cut underwater underwater is much less (112 KPa (16 psi) instead of 840 KPa (120 psi) for in air). The disadvantage is that the jet's effective cutting distance reduces from about 15 m to about 3 m. To mitigate this, a new tool has been invented that brings the water jet nozzle close to the face. This invention has been tested at a 1/4 scale model and has proven its feasibility. Now a 1/2 scale model is being studies and is expected to be tested in the next two years. The details of these models are proprietary.

Computer Mathematical Model. The computer modelling program of the borehole mining processes began in 1989. The scope was divided into two basic parts; the first was to develop a model to simulate the hydraulic jetting of the oil sands and the production of the resulting slurry. It deals with the cutting characteristics of water jets on the oilsand as a function of time, pressure and flow rates, etc., and the dynamic flow conditions of the resulting slurry in the cavity and up the borehole to the surface. This model does not consider the geotechnical properties of the oilsand such as sloughing or subsidence in the cavity or on surface.

The second part of this mathematical model development program deals with the geotechnical aspects of cutting the oilsands in an underground water filled cavity. Laboratory tests to determine the oilsands properties were performed to ascertain some basic geotechnical properties for the mathematical model. Using this data, a subroutine was developed for sloughing of the roof strata in a borehole cavity. The subroutine is built on a simple analytical model, and gives approximations of the strata failure processes. Their applicability and limitations will be explored as future studies are undertaken, and as data is obtained on the *in-situ* oilsands properties, a more advanced model will likely evolve.

The model development and theoretical analyses of the borehole mining process will continue in 1990, with parametric studies on the mathematical model being the primary tool. More core and field data will be collected to substantiate further development of the mathematical and computer models for the borehole mining processes.

Tailings Management

The test work carried out on the OCWE process tailing indicates to date that the fines (less than 22 microns) settle very fast and consolidate to about 30% solid within one to three months. These solids then can support a surcharge layer of coarse sands.This offers the possibilities of layering fines and coarse sand alternately, which may eventually result in a sand/fines disposal area rather than a tailings pond, thus producing a solid tailings area at the end of the project. A solid tailings management scheme that will have alternate layers of fines and solids has already been tested in the laboratory and will be tested on a larger scale in the 1991-92 period.

In the borehole mining system, about 75% or more of the coarse sands that settle almost immediately will be left in the cavity. The fines will come up to the surface with the slurry flow and will be processed by the OCWE process. The fines then will be pumped to the tailings pond where these will be allowed to settle and consolidate for 1-3 months and then layered over by the coarse sands. This , together with the reduced sand volume,results in a tailings management scheme that could be environmentally and economically superior to the present commercial projects schemes.

Costs and Risks

The following costs and risks are associated with the borehole mining technology developed to date.

Costs. The preliminary feasibility study for borehole mining was based on a commercial project size of 4800 m^3/day (30,000 bbl/day) of bitumen.

The study indicated that the project life operating cost was $9.50/bbl (1989 $) and the capital cost was $2.50/bbl, the total cost (capital and operating) is 12.00/bbl. This represents significant reductions from the costs of initial studies ($16.00/bbl) undertaken on a 10,000 bbl/day project in 1986.

It is anticipated that,as more knowledge is gained and data gathered from the technology development program, the process would be further optimized

Risks. The following aspects of the borehole mining technology will present risks.

1) Mining Tool: The new tool custom made for the oilsands needs to incorporate the idea of bringing a jet nozzle close to the face and the design has to be rugged and practical. The tool has to be mobile enough and must include remote control technology to reduce the

operating costs.

2) Extraction Process: The OCWE process has essentially made the borehole mining system economic. This process has been demonstrated on a 15 tonnes/hour continuous pilot and will be demonstrated at an 800 tonnes/hour pilot during 1991-92. If the process does not scale-up as envisaged to date, the costs may be affected.
3) Cavity Stability: This is the most critical area of the technology. If the hydraulic head support system does not work as envisaged, a caving system may have to be employed which could reduce the bitumen recoveries. Other conventional methods of supporting the cavities such as cementation, freezing or pressurizing with gas may not be cost effective.
4) Surface Subsidence: It is anticipated that the cavities will be backfilled with the spent sands and these will mitigate the subsidence on surface. The actual amount of subsidence will depend on the size of the cavity and the nature of the overburden as well as the quality of the backfill.
5) Costs: the present costs at $12.00/bbl are dependent on the assumptions used in the feasibility study, and several of these need to be confirmed by the pilot programs planned for 1992-93.

FUTURE PLANS

The objectives of the 1990 test program are to conduct shallow cavity tests on Lease 41, to examine the mining and stability aspects of borehole mining technology. Efforts will be made to process the borehole mining slurry using the OCWE process to verify the applicability of the extraction technique for borehole mining. Further studies and tests on the new mining tool, geotechnical and process modelling will be carried out to assess the underground borehole mining concept in a flooded cavity.

The data base and analyses results obtained in 1990 will form the basis of the 1991 engineering design for the deep hole (60 m depth or more) cavity tests in 1992 and 1993, also to be on Lease 41. About 4-6 cavities are planned. The borehole mining equipment to be used is the system which OSLO bought from the Union Pacific Resources of Colorado in 1989.

Assuming that these tests are successful, the application of borehole mining technology to the Athabasca resource will reach a semi-commercial stage at a larger pilot beyond 1993.

CONCLUSIONS

The following conclusions can be drawn from the OSLO borehole mining technology development program to date:

- OSLO has a large oilsands resource that lies at 50-150 metres depth for which no known technology is applicable. The borehole mining technology has become potentially applicable due to a number of innovations and discoveries that OSLO has made over the past five years as follows:
  - the water jet cutting pressure under water on surface oilsand is only 112 KPa as compared to the earlier known pressure of 1.2 MPa for cutting in the air. The low cutting pressure will be made possible by bringing the jet nozzle from the tool near to the cutting face, in an underwater environment, to minimize effects of the stand off distance.
  - the cavity integrity may be cost effectively maintained by using the hydraulic head in a fluid filled cavity.
  - less than 25% of the oilsand in a cavity is pumped to surface, the rest will be partially processed in the cavity by removing bitumen from the oilsand into the water phase and then pumping the fines-water-bitumen mixture to surface, leaving the coarse spent sands in the cavity.
  - the OCWE process is synergistic with the borehole mining produced slurry. The process works at ambient temperatures (3°C - 25°C) and is being developed under OSLO's dredging program.
- The development of a borehole mining mathematical computer model has been initiated to simulate various processes occurring in the cavity, to help in parametric studies and operating issues.
- OSLO now owns the most advanced borehole mining system available, which now allows the actual testing of borehole mining to be carried out in situ down to 120 metres depth.
- The project life costs are about $12.00/bbl bitumen using the present innovations. The technology may become more economic as new ideas emerge in the continuing development.
- OSLO and AOSTRA are planning to initiate a pilot in 1992/93 when 4-6 deep cavities will be mined. This pilot will prove up the technology for installing commercial projects for OSLO Leases as well as for the rest of the Athabasca oilsands.

Acknowledgements

The authors thank the OSLO owners and AOSTRA for allowing the publication of this paper.

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VOID SPACE CREATION

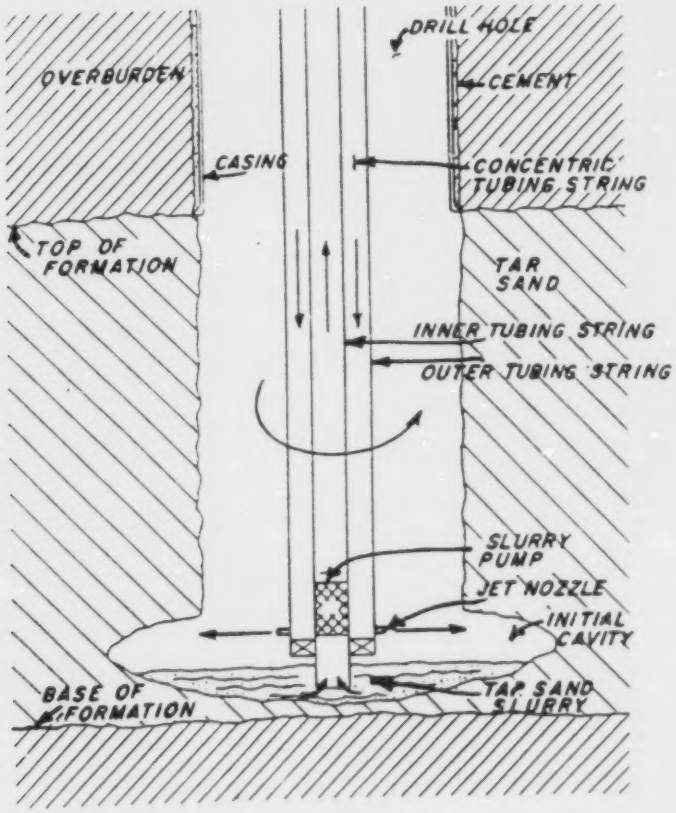

FIGURE 1

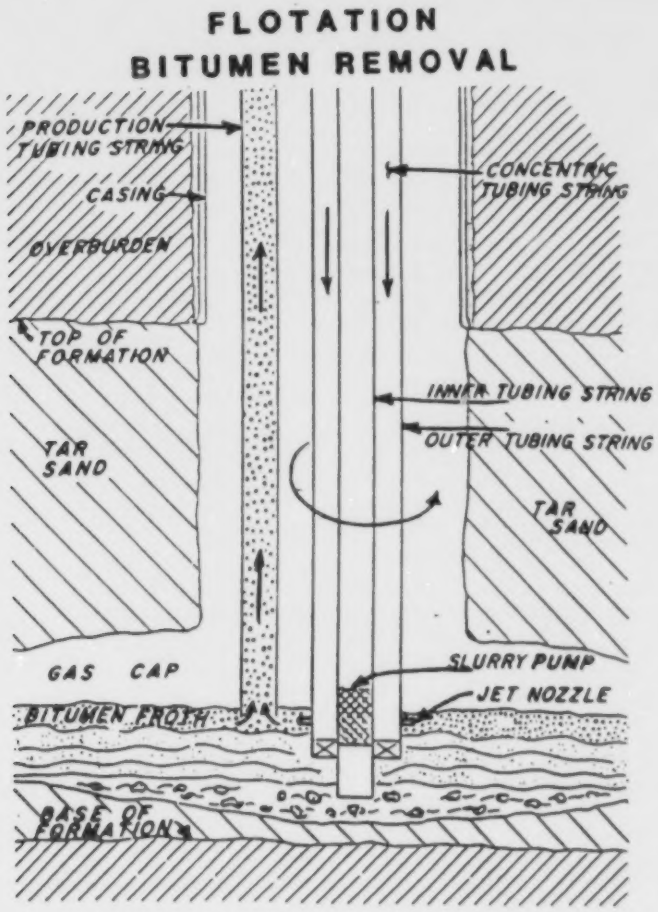

FIGURE 2

BOREHOLE MINING SYSTEM DIAGRAM

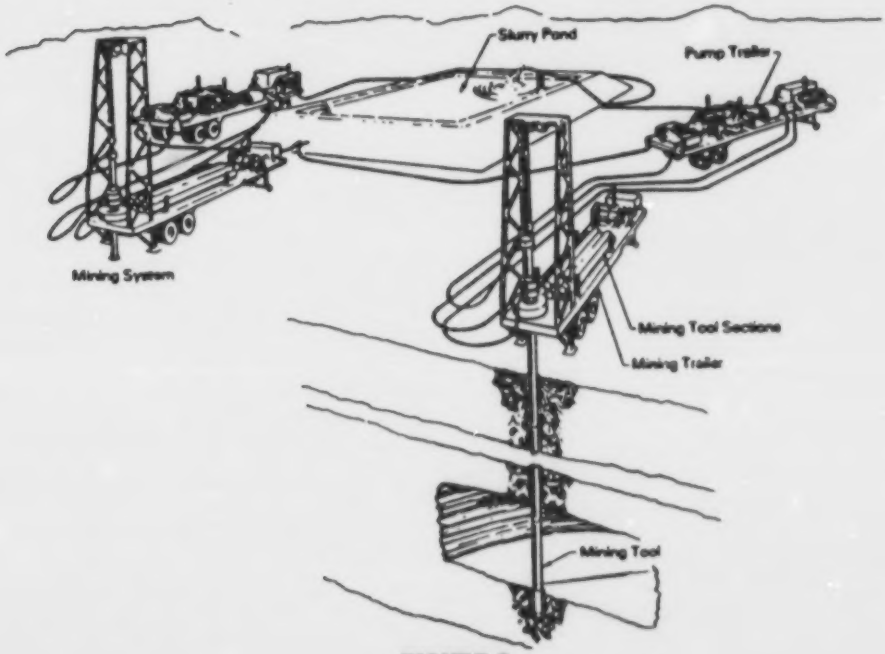

FIGURE 3

SEQUENCE OF CAVITIES MINED

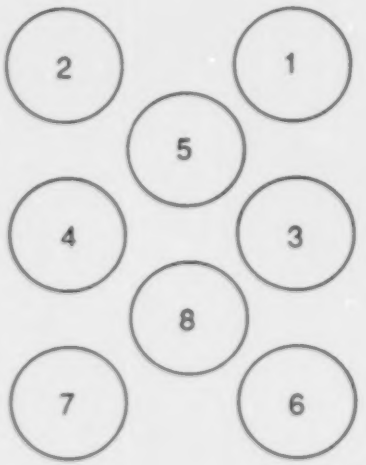

FIGURE 4

1988 LEASE 41 TEST SET-UP

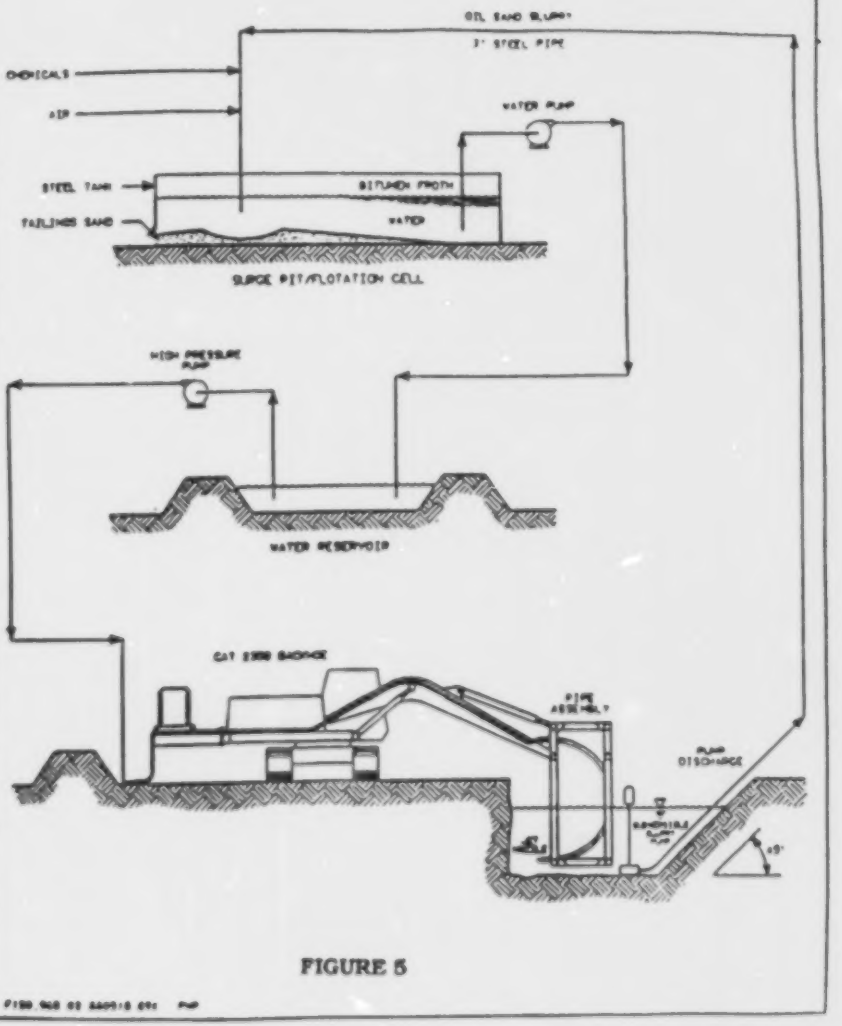

FIGURE 5

Development Of High Conversion Process For Upgrading Alberta Bitumen

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Abstract. A high conversion process for hydrocraking of bitumen is being developed jointly by the Alberta Oil Sands Technology and Research Authority (AOSTRA) and the Alberta Research Council (ARC). The experimental program is progressing using a 2 kg/h pilot-scale plant equipped with a tubular reactor. Experiments performed using the feedstock, vacuum bottoms from Cold Lake (Alberta, Canada) bitumen, yielded above 95% conversion, above 85% liquid distillate yield, significant sulfur removal (> 80%), high product quality (API gravity of 29), but no coke formation. Reactor hydrodynamics under process conditions were studied using radioactive tracers to yield a four parameter model, consisting of gas hold-up, liquid and gas phase Peclet numbers and interfacial area - interfacial mass transfer coefficient per unit reactor volume. Process data were interpreted in terms of a convolution of the hydrodynamic model and the kinetics of lumped chemical species. Rates and activation energies of the hydrocracking reactions were obtained. The effects of temperature and hydrogen partial pressure on hydrogenation kinetic rate constant were correlated in the form of $k_H = A_H \exp(-E_H / R_T) P_H^{0.5}$. It is believed that these studies are sufficient for process design and scaling.

Introduction

In 1982, AOSTRA and industry collaborated in an evaluation of the relative economic feasibility of promising upgrading processes, pilot to commercial scale. An important conclusion was that high conversion hydrocracking processes are most promising for upgrading bitumen and that fouling of heterogeneous catalysts would be significant. For this reason, laboratory studies were started here to develop hydrocracking processes using homogeneous catalysts.

An experimental program was implemented using a 2 kg/h pilot plant test facility equipped with tubular reactors of 2.5 cm I.D. and 67 cm length, and 2.5 cm I.D. and 135 cm length. Hydrocracking characteristics of Cold Lake (Alberta, Canada) bitumen vacuum bottoms under different operating conditions were measured. The effects of the following on hydrocracking yield and product distribution were studied: load of homogeneous catalyst, temperature, pressure, and feed rates of liquid and gas. Furthermore, engineering analyses using radioactive tracers provided a simple description of the hydrodynamics of the reactor. In this paper, a method is described to simplify the scaling of this and similar reactors. The method obtains a least squares fit of the process data in terms of a convolution of the reactor's hydrodynamics and the hydrocracking kinetics. It is believed that the method described here is sufficient for many exercises of process design and scaling.

Experimental

Cold Lake (Alberta, Canada) vacuum bottoms were supplied by the ESSO Strathcona Refinery in Edmonton. The properties of the vacuum bottoms are listed in Table 1. To these bottoms were added a small amount of bitumen to provide the feedstock having properties described in Table 2.

Data reported herein were obtained from the continuous tubular reactor system, which is shown schematically in Figure 1. The system is composed of four major modules: gas and liquid feed section, preheater-reactor section, product separation-collection section and process control section.

In the gas feed section hydrogen was supplied from the auxiliary compressor at 35 MPa pressure and was controlled by automatic pressure regulators, a control valve and a mass flow meter before entering the preheater-reactor section.

The feedstock was pumped into a 0.01 m^3 feed tank and was mixed therein with a homogeneous

catalyst obtained from K&K Laboratories, New York, NY.

The preheater consisted of a long, stainless steel coil (0.3 cm I.D. and 610 cm length) immersed in a fluidized sand bath of temperature 400°C. The process line from preheater to the reactor was relatively short and its temperature was traced to minimize cooling of the slurry before entering the reactor.

The reactor was made of 316 S.S. tube (2.5 cm I.D. and 67 cm length, and 2.5 cm I.D. and 135 cm length) manufactured by Autoclave Engineers, Erie, Pennsylvania, and was designed to operate at pressures less than 28 MPa and temperatures less than 530°C. Liquid hourly space velocities (LHSV) in the range, 0.5 to 4.0, were easily obtained.

Products were separated using alternative hot separators. The one had 0.002 m^3 volume and was used during the steady-state operation of the unit. The liquid product from this separator was transferred into two low pressure, low temperature product vessels. The other had volume of 0.004 m^3, was connected to a 0.016 m^3 dump vessel, and used during the unsteady-state operation of the unit. Both hot separator trains shared the same product gas line which consisted of three water cooled condensers and two gas collection tanks.

Control and monitoring of the tubular reactor system were done from a remote operator control station. The process operating conditions, such as system pressure, reactor and furnace temperatures, slurry and hydrogen feed rates were controlled and continuously recorded from the control station. The system was protected by automatic fail-safe devices with provision for emergency shutdown.

In a typical residue hydrocracking experiment, feedstock in the feed tank (at 150°C) was stirred and recycled in order to maintain homogeneity. Two high pressure, positive displacement pumps transferred the feed from the feed tank to the preheater where feed was mixed with hydrogen. The hot mixture entered the bottom of the reactor. For these experiments a reasonably close approach to steady-state conditions was obtained after 4-6 hours of operation. Nevertheless, after each experiment equipment was disassembled to observe any coke or other material that may have been deposited.

Hydrocracking experiments were performed under the temperature range of 425-485°C, hydrogen and bitumen residue feed rates of 8-28 *slpm* and of 1.2-4 *LHSV*, respectively. Reactor pressure was kept constant at 17.5 MPa for the most of the experiments. The temperature of the hot separators was 250°C.

Liquid products were depressurized by isolating the hot separator after each yield period, and then automatically throttling the liquid products into the atmospheric pressure collection vessels. When depressurization was completed, the hot separator was repressurized with nitrogen to the system's pressure and put into operation. This technique minimized fluctuations of system pressure caused by removal of liquids or upsets due to plugging of the continuous relief valve.

The gases from the separator were cooled in condensers, then passed through a dry gas meter to gas collection tanks. After each run was completed, gas samples were taken from the gas collection tanks and analyzed by gas chromatography. Dissolved gases from the product collection vessels were recovered and collected in a separate gas tank. Gas samples taken from this gas tank were also analyzed by gas chromatography.

The liquid products were fractionated using a combination of atmospheric (ASTM D86) and vacuum distillation (ASTM D1160). The fractions obtained were naphtha (*NA*, IBP-195°C), light oils (*LO*, 195-350°C), heavy oils (*HO*, 350-525°C) and residue (pitch) +525°C. The residue was further separated into hydrocarbons, and asphaltenes applying a TLC/FID method (Selucky, 1983).

Seven tests were done to generate the preliminary data for the development of the kinetic model for bitumen catalytic hydrocracking and hydrogen consumption. The results of these tests are presented in Table 3. In all tests, important process parameters such as operating temperature, pressure, liquid and gas feed rates were continuously monitored and recorded. The mass balances for these tests were in the range of 98-100%.

In Figure 2 is shown the experimental arrangement for the tracer studies. Two radioactive isotopes, iodine (^{131}I, 1.2 nanograms, 150 μCi) and xenon (^{133}Xe, 2.1 nanograms, 400 μCi), were used to trace the liquid and gas phases, respectively, under hydrocracking conditions. ^{131}I chemically bound to an oil carrier remains in the liquid phase; it has a half-life of 8.05 days. ^{133}Xe is partitioned between the liquid and gas phases; it has a half-life of 5.27 days. Tracer experiments were performed by injecting iodine and xenon tracer as pulses at the reactor inlet, simultaneously or sequentially (xenon first), and were detected at the reactor outlet. Concentrations were recorded at 3 minutes and 6 seconds intervals for iodine and xenon, respectively.

Results and Discussion

Hydrocracking process performance was tested in the range of operating conditions; 400 to 500°C, 14 to 21 *MPa*, 0.5 to 6 *LHSV* and 14 to 28 *slpm* hydrogen gas feed rate. Test conditions and some product analyses are shown in Table 3. A typical simulated distillation analysis performed on product samples of naphtha, light and heavy oils is presented in Table 4.

In Figure 3 is shown a plot of measured conversion of asphaltene versus that of pitch. It is

noteworthy that for conversions of pitch less than 80%, the conversion of asphaltene was constant at 60%. In the absence of catalyst and modest hydrogen overpressure, severe coking occurred. In the presence of catalyst, however, no coke was produced and the reactor was observed to be clean in subsequent disassembly. A reasonable hypothesis is that the catalyst shows high selectivity for conversion of asphaltene, because it forms a complex with the asphaltene moieties.

In Figure 4, sulfur removal is plotted and seen to be a linear function of pitch conversion. It may be concluded safely that while the removal is substantial, further hydrotreatment of some streams would be needed in a commercial unit.

In Figure 5 are shown typical plots of concentration of each tracer as a function of time. Superimposed on these plots are the simulated results obtained using a least - squares best - fit algorithm. This algorithm is based on the following equations describing the mass balances within the two - phase flow reactor (Aris, 1982; Danckwerts, 1953; Levenspiel and Bischoff, 1963):

$$\frac{\partial C_{1,l}}{\partial t_l} + \frac{\partial C_{1,l}}{\partial \xi} = \frac{1}{Pe_l}\frac{\partial^2 C_{1,l}}{\partial \xi^2} \tag{1}$$

for the iodine (soluble in the liquid phase only),

$$\frac{\partial C_{2,l}}{\partial t_l} + \frac{\partial C_{2,l}}{\partial \xi} = \frac{1}{Pe_l}\frac{\partial^2 C_{2,l}}{\partial \xi^2} + \frac{K_m aL}{\varepsilon_l v_l}\left(\frac{C_{2,g}}{H} - C_{2,l}\right) \tag{2}$$

for the xenon in the liquid phase, and

$$\frac{\partial C_{2,g}}{\partial t_g} + \frac{\partial C_{2,g}}{\partial \xi} = \frac{1}{Pe_g}\frac{\partial^2 C_{2,g}}{\partial \xi^2} - \frac{K_m aL}{\varepsilon_g v_g}\left(\frac{C_{2,g}}{H} - C_{2,l}\right) \tag{3}$$

for the xenon in the gas phase.

These equations include a description of the reactor hydrodynamics in terms of the four parameters: gas hold-up (ε_g), gas and liquid phase Peclet numbers (Pe_g and Pe_l) and the interfacial area - interfacial mass transfer coefficient per unit reactor volume ($K_m a$). Parameters describing reactor hydrodynamics such as gas hold-up, gas and liquid phase Peclet numbers and interfacial area - interfacial mass transfer coefficients are presented in Table 5 (Ozum et al, 1988 and 1989).

The hydrodynamic parameters determined above were used in the following equations describing the hydrocracking reactions (Kuo and Wei, 1969; Ozum et al. 1990; Wei and Kuo, 1969):

$$\frac{dC_{j,l}}{d\xi} = \frac{1}{Pe_l}\frac{d^2 C_{j,l}}{d\xi^2} + \frac{K_m aL}{\varepsilon_l v_l}\left(\frac{C_{j,g}}{H_j} - C_{j,l}\right) + \frac{L}{v_l} r_j \tag{4}$$

for the liquid phase, and

$$\frac{dC_{j,g}}{d\xi} = \frac{1}{Pe_g}\frac{d^2 C_{j,g}}{d\xi^2} - \frac{K_m aL}{\varepsilon_g v_g}\left(\frac{C_{j,g}}{H_j} - C_{j,l}\right) \tag{5}$$

for the liquid phase. Here $C_{j,l}$ and $C_{j,g}$ are the concentrations of the pseudo - components in the liquid and gas phases, respectively. These pseudo - components are the distillation fractions described in the experimental section: (525°C, *HO, LO, NA,* C_5 - C_6, C_1 - C_4 and H_2S. In the analysis, all reactions are assumed to be first order and are permitted between all components. The rates, r_j are therefore written as:

$$r_j = \sum_i k_{ij} C_i - C_j \sum_i k_{ji} \tag{6}$$

In Figure 6 are shown in schematic form the rate constants that are found to be significant. It is seen from Figure 7 that these constants conform very well to the Arrhenius relation:

$$k_{ij} = A_{ij} e^{-E_{ij}/RT} \tag{7}$$

The following equations describe the mass balances for hydrogen within the reactor:

$$\frac{dC_{H,l}}{d\xi} = \frac{1}{Pe_l}\frac{d^2 C_{H,l}}{d\xi^2} + \frac{K_M aL}{\varepsilon_l v_l}\left(\frac{C_{H,g}}{H_H} - C_{H,l}\right) + \frac{L}{v_l} r_H \tag{8}$$

for the liquid phase, and

$$\frac{dC_{H,g}}{d\xi} = \frac{1}{Pe_g}\frac{d^2 C_{H,g}}{d\xi^2} - \frac{K_m aL}{\varepsilon_g v_g}\left(\frac{C_{H,g}}{H_H} - C_{H,l}\right) \tag{9}$$

for the gas phase. Here, the liquid phase was assumed to be homogeneous in composition since the liquid phase Peclet number was small. The rate of consumption of hydrogen was assumed to take the following form:

$$r_H = -k_H C_{H,l}^n \tag{10}$$

Rate constants, k_H, were determined by a least - squares fit of process data. Throughout these calculations the previously determined hydrodynamic parameters were used. Henry's constants for hydrogen, H_H, were calculated according to Peng-Robinson equation of state.

In Figure 8 are plotted the calculated constants, k_H, as a function of temperature. It is seen that these

data conform very well to the Arrhenius relation:

$$k_H = A_H e^{-E_H/RT} \qquad (11)$$

The exponent n in Equation (10) was found to be 0.5. Much has been written about this exponent and reported values range from 0 to 2, depending mostly on the narrow ranges of pressures used by each experimenter (Lee et al, 1978).

Another series of experiments were done using a tubular reactor of twice the volume but of significantly different geometry. Different hydrodynamic parameters were obtained from the least - squares best fit of the data. However, the kinetic parameters were within the experimental error of those reported here.

Conclusions

In this paper, a simple axial - dispersion model was found to be sufficient to describe the performance of a pilot scale hydrocracker employing a tubular reactor. Kinetic and hydrodynamic parameters are reported for hydrocracking of bitumen in the presence of a homogeneous catalyst. The model was found to apply over a broad range of operating conditions and two reactor geometries. It is believed that the method described here is sufficient for many exercises of process design and scaling.

Acknowledgement

Special acknowledgement is given to Dr. J. Mercer and S. Hunt of Terabecquerel Tracers Ltd. of Edmonton, Alberta, Canada, who prepared and measured the radioactive tracers. Experiments and product characterization work were diligently performed by our colleagues, H.O. Kretschmer, K. Badree, J. Mendiuk, E. Fitzpatrick and B. Doherty. Much appreciated technical direction was provided by Mr. R.T. Bailey and Dr. C. Hsi of AOSTRA.

Nomenclature

a	gas-liquid interfacial area per unit reactor volume, cm^{-1}
A	pre-exponential coefficient, s^{-1}
C	concentration, $mol\ cm^{-3}$
E	activation energy, $kJ\ mol^{-1}$
H	Henry's constant
k	rate constant, s^{-1}
K_m	mass transfer coefficient, $cm\ s^{-1}$
L	reactor length, cm
$LHSV$	liquid hourly space velocity, s^{-1}
n	constant
Pe	Peclet number
r	reaction rate, $mol\ cm^{-3}\ s^{-1}$
R	universal gas law constant, $8.32\ J\ mol^{-1}$
$slpm$	standard liters per minute, $l\ min^{-1}$
t	time, s
t_g	dimensionless time ($t_g = v_g t/L$)
t_l	dimensionless time ($t_l = v_l t/L$)
v	velocity $cm\ s^{-1}$
X	distance from reactor inlet, cm

Greek Letters

ε	holdup
ξ	dimensionless distance

Subscripts/Superscripts

1	iodine
2	xenon
l	liquid phase
g	gas phase
H	hydrogen
j	specie

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Table 1: Properties of Cold Lake Vacuum Bottoms (+430°C)

Distillation, wt%	
IBP–525°C	24
+525°C	76
Elemental Composition, wt%	
Carbon	83.6
Hydrogen	9.7
Nitrogen	0.8
Sulfur	5.9
Oxygen	–
H/C	1.39
Metals, ppm	
Vanadium	238
Nickel	108
Iron	63
TLC/FID Class Composition, wt%	
Hydrocarbons	75.0
Asphaltene	25.0

Table 2: Feedstock Component Breakdown

	Naphtha			Light Oil		Heavy Oil	Residue
tbp	C_5–70°C	70–160°C	160–205°C	205–345°C	345–370°C	370–525°C	+525°C
wt%	0.1	0.4	2.1	14.4	4.4	24.4	54.2
wt%		2.6		18.8		24.4	54.2

Table 3: Data Summary for Kinetic Model Development

Feed: Cold Lake Vacuum Bottom **Hydrogen Pressure H_2: 17.5 MPa**

Run No.	Temp. °C	LHSV h^{-1}	H_2 Feed Rate slpm	Mass Balance	Product Yield, wt% on feed							H_2 Consump. % wt on feed
					C_1–C_4	C_5–C_6	H_2S	IBP–195°C	195–350°C	350–525°C	+525°C	
24YP1	425	1.2	15	98	2.01	0.34	1.81	1.10	16.13	35.35	43.04	2.39*
27YP1	455	2.5	13	97	3.84	0.54	2.29	4.15	25.02	34.15	28.10	1.02
28YP1	455	4.0	14	96	2.80	0.51	1.84	2.79	20.35	32.87	35.77	0.80
29YP1	455	4.0	28	99	2.93	0.49	1.90	2.76	19.91	35.29	36.02	0.78
34YP1	470	2.5	14	97	7.21	1.08	3.31	6.79	34.36	30.46	14.61	1.29
34YP2	470	4.0	14	98	5.88	1.05	2.89	4.77	31.09	30.83	22.16	1.04
40YP1	440	1.2	14	100	3.63	0.64	2.60	2.98	22.15	37.02	32.07	1.19

* H_2 concentration measurement had error (to be repeated)

Table 4: Distillation Analysis (D2887 Method) of Product from Case TRU 27 YP1

Cum wt% off	True Boiling Point Temperature °C		
	Naphtha	Light Oil	Heavy Oil
I.B.P.	63	113	296
5	86	143	339
10	93	163	355
15	97	179	367
20	100	194	377
25	111	208	386
30	114	219	395
35	117	229	404
40	122	240	412
45	125	248	420
50	129	258	428
55	135	67	436
60	139	277	444
65	144	286	453
70	149	295	461
75	157	304	471
80	165	314	480
85	174	325	490
90	191	336	501
95	214	350	515
E.P.	308	385	545

Table 5: Estimated Reactor Parameters

Run	v_l cm/s	v_g cm/s	Pe_l	ε_g	Pe_g	$K_m a$ s^{-1}	H
1	.0229	0.67	0.67	0.73	8.4	.019	2.6
2	.0476	0.67	0.69	0.73	8.3	.020*	2.6*
3	.0762	0.67	0.74	0.72	8.0	.020*	2.6*
5	.0762	0.38	0.77	0.73	7.1	.020	2.6
3	.0762	0.67	0.74	0.72	8.0	.020*	2.6*
4	.0762	1.34	0.71	0.72	9.6	.020*	2.6*

* Preset with fixed values (Ozum et al., 1989)

Table 6: Molar Composition of Product Using HYSIM for Case TRU 27 YP1 at 2500 psi and 455°C

Component	Total Stream	Vapour	HC Liquid	Henry Constant
Hydrogen	0.89339	0.91934	0.29991	3.0654
Methane	0.01354	0.01387	0.00597	2.3228
Ethane	0.00609	0.00620	0.00352	1.7616
Propane	0.00422	0.00427	0.00300	1.4254
I-Butane	0.00064	0.00064	0.00053	1.2079
n-Butane	0.00205	0.00206	0.00179	1.1511
I-Pentane	0.00056	0.00056	0.00059	0.9578
n-Pentane	0.00084	0.00084	0.00089	0.9429
n-Hexane	0.00017	0.00017	0.00022	0.7775
H_2S	0.01440	0.01460	0.00990	1.4749
Naphtha	0.00733	0.00706	0.01360	0.5186
Light Oil	0.02545	0.02161	0.11327	0.1907
Heavy Oil	0.01923	0.00805	0.27483	0.0293
+525°C Res	0.01209	0.00073	0.27199	0.0027
TOTAL	1.00000	1.00000	1.00000	
kg/hr	0.84750	0.43020	0.41730	

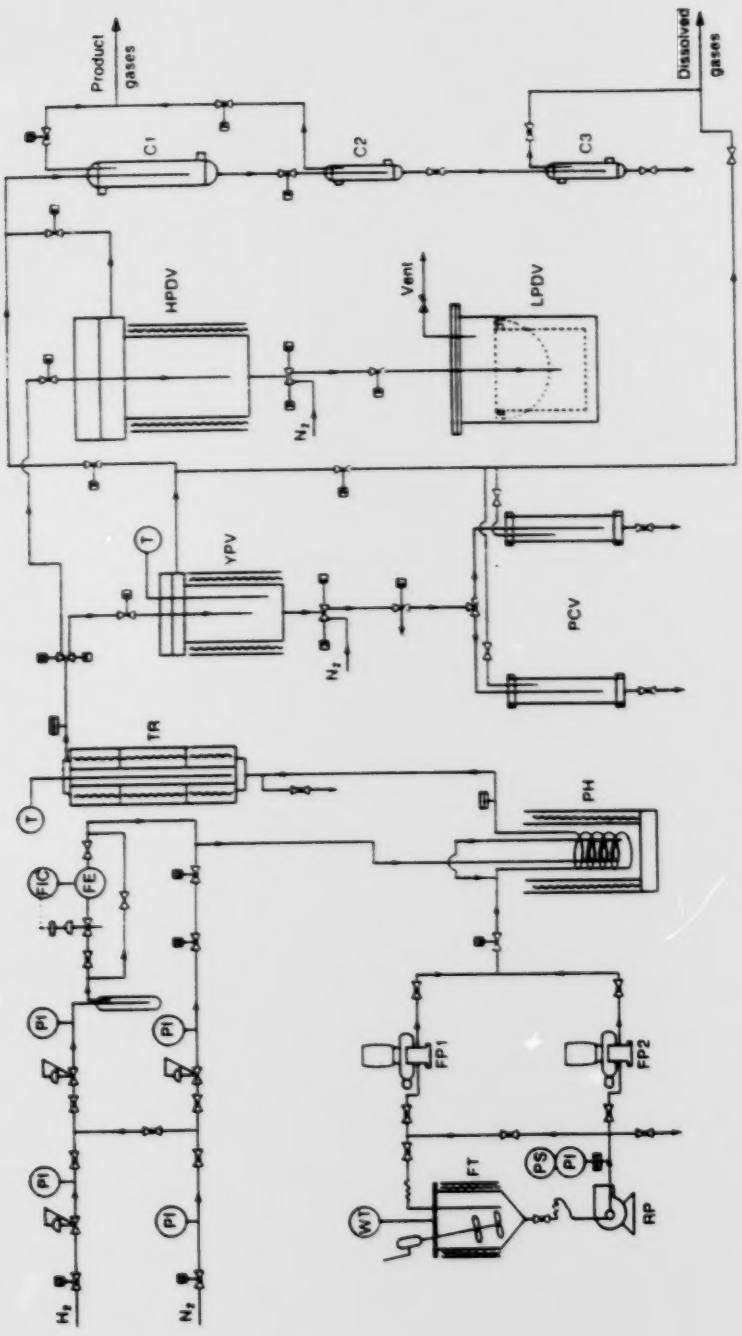


Figure 1 : Reactor schematic for bitumen residue hydrocracking process.

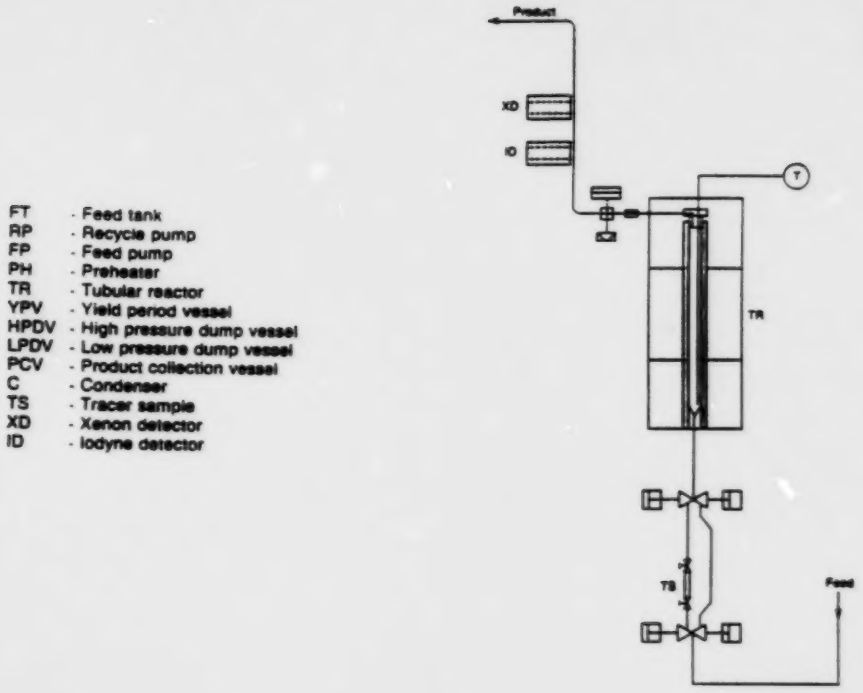


Figure 2 : Schematic of the tracer injection system.

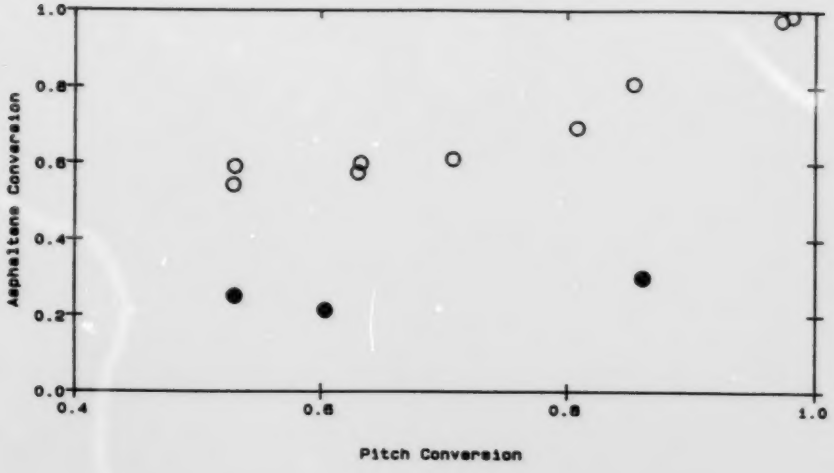


Figure 3 : **A plot of asphaltene conversion versus pitch conversion (solid circles are the non-catalytic runs).**

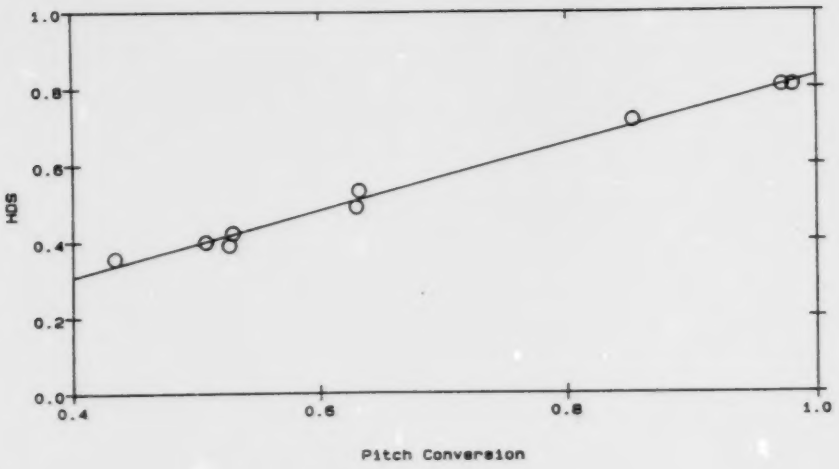
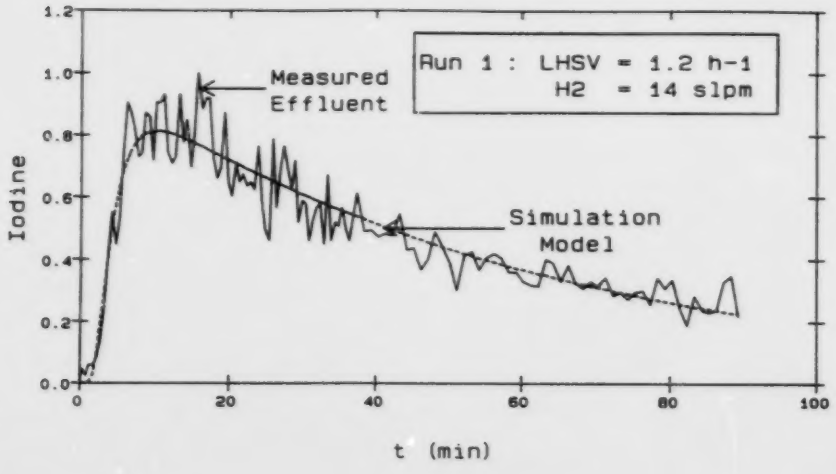


Figure 4 : A plot of % sulfur removal versus pitch conversion.



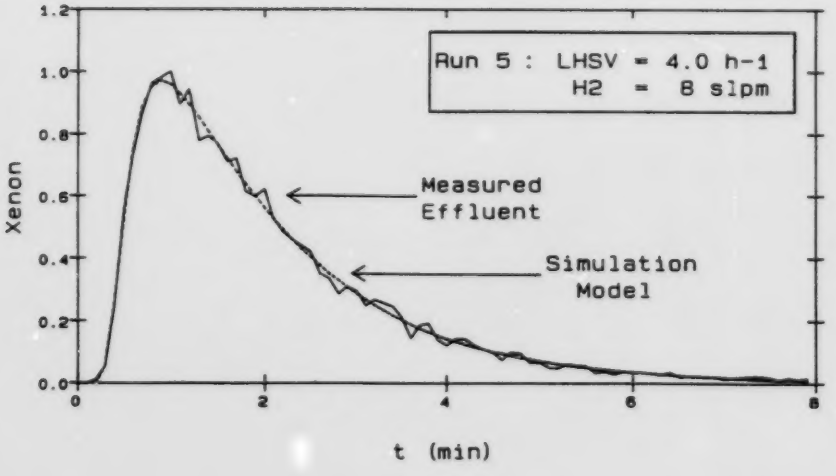


Figure 5 : Typical liquid and gas tracers measurements as a function of time.

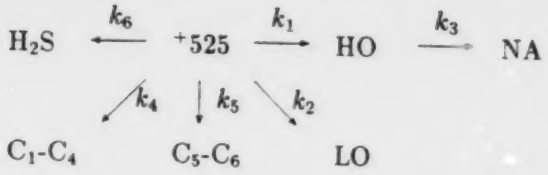


Figure 6 : Reaction network suggested for the hydrocracking process.

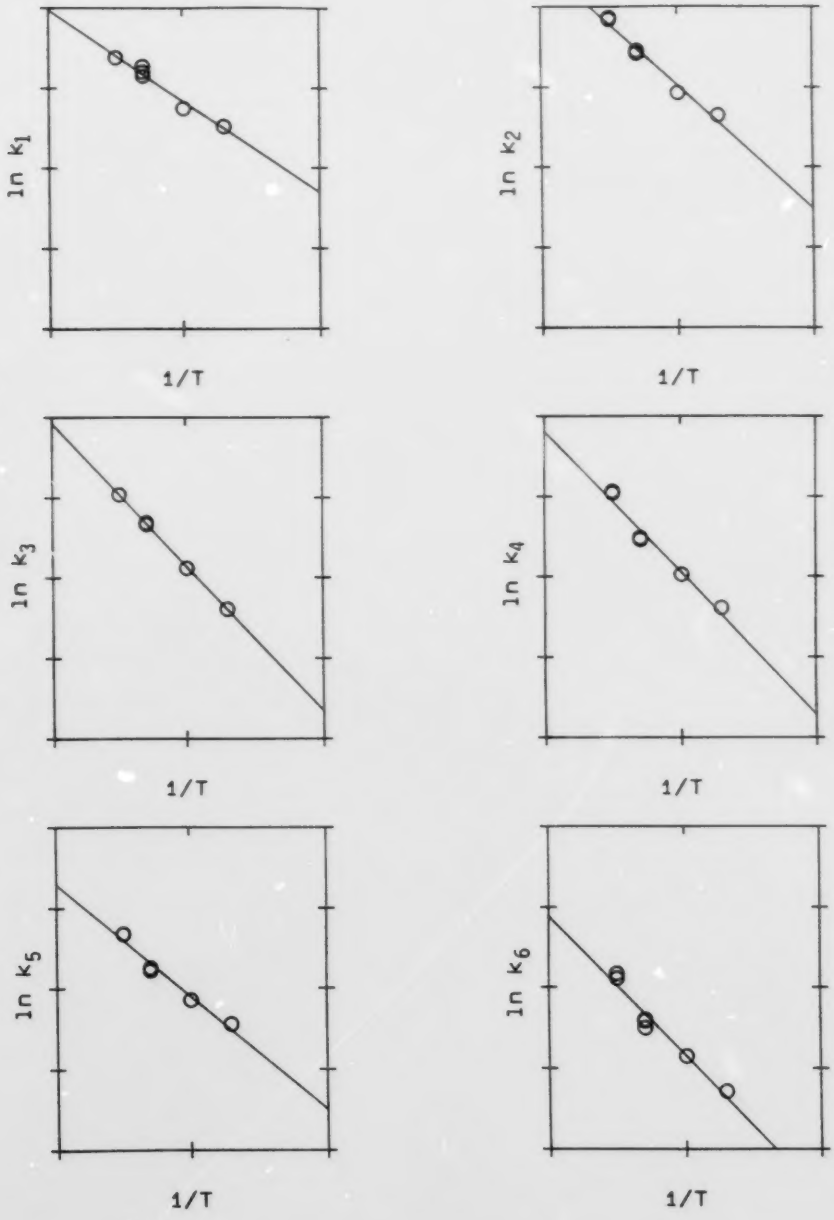


Figure 7 : Arrhenius plot for hydrocracking rate constant.

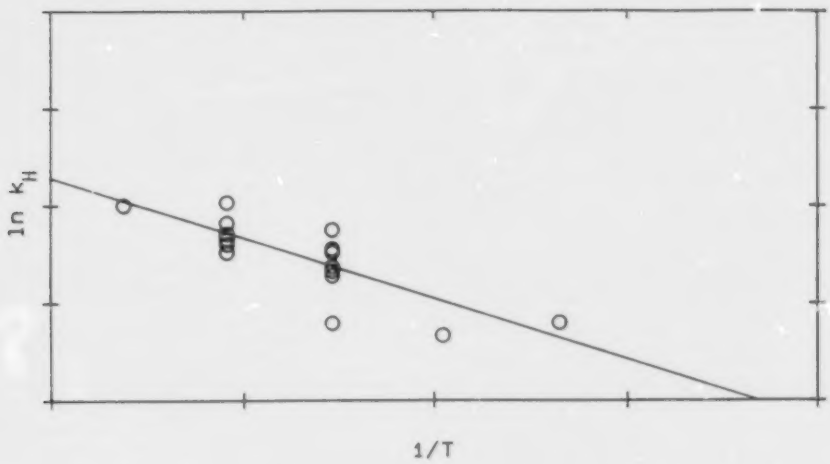


Figure 8 : Arrhenius plot for hydrogenation rate constant (n = 0.5).

Upgrading Shale Oils For The Australian Market

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Abstract. The tertiary oil shale deposits of Queensland Australia contain some 27 billion barrels of insitu shale oil. This represents a reserve of ten times that remaining in Australia's largest crude oil field in Bass Strait, and is equivalent to 100 years of Australia's current oil usage.

As distinct from the sweet Australian crudes, shale derived oils require upgrading to reduce metals and heteroatom concentrations. These upgrading operations, while not posing new problems for the petroleum industry in general, are not currently widely employed in Australian refineries.

In order to decide on the optimum upgrading route, certain factors need to be considered, including: probable markets, oil characteristics, installed processing facilities in local refineries, and plant economics.

This paper discusses these items in the context of the commencement of a shale oil industry in an increasingly liquid fuel deficient Australia.

INTRODUCTION

The production of indigenous crude in Australia is projected to drop sharply over the next decade, which will necessitate importing almost half of the expected demand by the year 2000. The existing refineries have been built up around processing of the light sweet Australian crudes, and so do not have the necessary equipment to process raw shale oils with their relatively high heteroatom concentrations combined with high Bromine Numbers.

Southern Pacific Petroleum and Central Pacific Minerals (The Companies) have reserves of over 20 billion barrels of oil shale in Queensland, and are actively pursuing the design of a semi-commercial plant on the Stuart Deposit, 15 km north of Gladstone.

The development of an oil shale industry will be dependent upon the supply of upgraded shale oils as preferred feeds for the existing refineries.

This paper presents the properties of the various shale oil cuts and discusses the results of a number of upgrading studies aimed at achieving the best plant configuration through the developmental stages of the first oil shale project.

THE EXISTING AUSTRALIAN SITUATION

Petroleum Refining

Major changes are occurring in the Australian Oil Industry. These changes are being catalysed by a number of coincidental factors including:

- A decline in indigenous crude oil production,
- Deregulation of the supply market by the Federal
- Government,
- Changing demand patterns.

Australia's self sufficiency in transportation fuels has started to decline and not even the most vigorous exploration program is likely to reverse that trend. Figure 1, Australian Oil Supply and Demand, is a compilation of Federal Government and APEA published Data[1] and forecasts Australian consumption to rise to 800,000 bbl/d by the year 2000. If we accept their projections of production from known reserves and from new discoveries, Australia will then be facing a shortfall in oil production of nearly 400,000 bbl/d.

During the period of self sufficiency using indigenous crudes, the Federal Government regulated the allocation of these crudes to the eight refineries. The total refining capacity[2] of the refineries, seven of which lie on the populated eastern seaboard and one 3000 kilometres to the west, is about 700,000 bbl/d, compared with the demand of about 630,000 bbl/d in 1988.

Indigenous crude oil production is light and sweet and in 1988 met about 90% of demand, but projections show this falling to 39% by the year 2000. The Refiners will therefore be forced to either import a "cocktail" of crudes/feedstocks to resemble

current feeds or to upgrade refineries to accept other feedstock. Based on world statistics[3] of existing reserves there is more heavy crude than light crude, particularly the low sulphur light sweet crudes. Therefore there is likely to be an ever increasing price differential favouring light crude over heavy crude.

The demand for transportation fuels is increasing[1], notably unleaded petrol — rising from a current base of 17% to 86% by the year 2000 with an concomitant 15% rise in demand. Similarly, automotive diesel fuel demand is expected to rise by 48% over the same period, which amounts to a real increase of 27.8 million barrels per year. Figure 2 shows the projected change in product demand over this period.

In order to meet demand, a number of the Australian refineries[2] are adding processing units which will allow them to process the lower priced crudes. The challenge for the synthetic fuel industry is therefore emerging, especially when it is considered that fresh field exploration costs in Australia are running as high as $US20 per barrel of oil brought on line.

Tertiary Shale Oil Resources in Queensland

Eight deposits of Tertiary oil shale have been identified within the coastal region of the State of Queensland, Australia. As shown in Table 1 they contain some 27 billion (i.e.thousand million) barrels of in situ shale oil of which the Companies own a net interest of some 20 billion barrels.

The location of these Queensland deposits provides advantages not found elsewhere in the world. They are close to infrastructure including power, abundant water, port facilities, labour, and are suitable for open pit mining. The weather and altitude are similar to the Gulf Coast of the U.S.

The shale oils derived from these products are relatively low in sulphur, nitrogen and metal impurities compared to other oil shale derived oils[5]. However they differ markedly from the indigenous Australian crudes. Table 2 compares Raw shale oil from the Stuart deposit with typical Gippsland crudes[6] and Syncrude synthetic crude oil (SCO)[7].

DEVELOPING AN OIL SHALE INDUSTRY IN AUSTRALIA

The major problem confronting the oil shale industry worldwide is the relative abundance of cheap crude oil. However, this oil is in the hands of a select few countries, but not the major users who affect the demand side of the balance. The result has been periodic wild swings in crude prices.

The major technical problem is in the area of retorting which when based on conventional refinery technology, and together with necessary upgrading equipment to produce an acceptable syncrude, demands a projected capital repayment charge of the order of $US20–30/bbl on new plant[8] based on US shale processing.

The Companies are intent on developing a viable oil shale industry in liquid fuel deficient Australia using AOSTRA technology developed for the extraction of oil from oil sands. Unlike the refinery based designs, the AOSTRA Taciuk Processor (ATP) is based on conventional solids handling technology and employs rotatory kiln technology to preheat, retort, combust and cool the –6 mm shale feed in the one multi compartment kiln.

The Planned Development of the Stuart Resource is in three stages, (refer to figure 3) commencing with a low capital cost, semi-commercial plant at 6000 tonnes/day of high grade shale feed producing 4250 bbl/d of oils. Once the retorting technology is proven the second stage plant at 25,000 t/d of shale producing 14,000 bbl/d of syncrude from an intermediate grade will be constructed. Stage three is a replication step with five 25,000 t/d units producing 60,000 bbl/d of syncrude from average grade shale, or approximately 15% of the projected Australian import requirement in the year 2000.

The product oil from the ATP is a full ranged thermally cracked oil with characteristic low viscosity, and low density. Therefore the steps in which crude bitumen is handled in Canadian tar sands projects are avoided. The cut point of 510°C+ for the heavy ends, represents a significant step in the development of oil shale retorting technology. Results from test runs on the various retorting technologies studied, indicated that the fractionator bottoms which contain the shale ash fines from the retort, could be returned to the retorting zone without appreciable yield loss. Recycling the bottoms had the added benefits of minimising the handling of residues and avoiding the necessity to separate solids from heavy oils with the attendant tailings ponds and their environmental problems.

The Stuart shale is composed of clays[9], with the major minerals being smectites and kaolinite, and does not undergo any appreciable size change during retorting. The resultant shale ash, partially combusted spent shale from the retort with approximately 5% wt carbon, has an open pore structure with a surface area of 40 m^2/g, which compares with a typical cracking catalysts at 150–200 m^2/g.

The effect of spraying the residue onto the shale ash bed in the retorting zone is analogous to that achieved by catalytic cracking with a slight reduction in density of the whole oil product. In addition there is a beneficial reduction in metal, principally arsenic, and nitrogen content of the product as their concentrations tend to rise sharply in the vacuum resid.

The product cuts within a synthetic crude must be suited to the market place. It is apparent from

Table 2, the raw shale oil will need pretreatment before it can be processed by Australian refining plant. Therefore, the Companies's aim in the Stuart Development is to undertake minimum upgrading of shale oils on site, in order to provide a marketable feedstock without duplicating processing plant in existing refineries.

In keeping with this objective, the first plant must seek to maximise revenue at minimum capital cost, while achieving the necessary demonstration of scaleup of the ATP. As any Australian shale oil products used in the production of gasoline for the Australian market do not attract an excise from the Federal Government, the first plant must produce a naphtha suitable as a refinery feedstock.

The properties of the various fractions of raw shale oil from the Stuart Kerosene Creek Member with comparisons of Gippsland and Syncrude synthetic crude oil (SCO) are presented in Tables 3 to 6.

SHALE OIL UPGRADING

A number of hydrotreating studies have been undertaken by the Companies on the typical cuts of shale oil from various Queensland deposits utilising a number of retorting technologies. These studies included investigations of the conditions required to hydrotreat Stuart shale naphtha to Catalytic Reformer feedstock quality, co-processing of blends of Stuart shale oil and petroleum crude derived gas oil cuts, and hydrotreating of the whole oil from the Condor deposit.

Test work was conducted in a number of independent laboratories using pilot plant fixed bed reactors with once through hydrogen treat gas flows.

Naphtha Hydrotreating

Shale naphtha contains high quantities of nitrogen, sulphur and has high Bromine and Diene Numbers together with some low levels of metal contamination. The procedures adopted in hydrotreating shale naphtha need to be specific to the feed properties, as different retorting technologies tend to produce variations, and the required product quality. In this case the product quality must match gasoline reformer feedstock which demands sulphur and nitrogen concentrations below 1 ppm wt.

The steps in the hydrotreating process include metals removal, saturation of dienes and olefins followed by deep denitrification and desulphurisation. The olefin saturation reactions are the first to proceed and are highly exothermic. In hydrotreating the shale naphtha with a Bromine Number of 95, the dissipation of this heat of reaction in a gas phase reaction needs to be addressed. The need to dissipate this heat could be avoided if the naphtha were to be pretreated as a part of a wider cut or a whole oil hydrotreating step but at a significant capital cost penalty to the first plant.

During a set of test runs to determine favourable hydrotreating conditions for design, Stuart shale naphtha was successfully hydrotreated to gasoline reformer quality, using commercial catalysts and moderate pressures. The required nitrogen removal of over 99.9% was readily achieved. The test conditions were held over a thirty hour mass balance period at normal space velocities and equivalent Start of Run temperatures. Catalyst life maintenance tests will be conducted as a part of an ongoing program.

In the first saturation beds, the sulphur proved relatively more easy to remove than the nitrogen, as concentrations of 90 and 1500 ppm wt respectively were recorded coincident with the completion of the olefin saturation. Deep denitrification and desulphurisation were subsequently performed over a more active catalyst at higher temperatures and the same total pressure.

Water washing of the hydrotreated naphtha samples was used to remove trace quantities of ammonia and hydrogen sulphide with remnant nitrogen and sulphur concentrations determined by the chemiluminescence technique. Water washing had to be performed as soon as possible after taking the sample, as failure to undertake this step or other corrective measures resulted in a seemingly refractory core of sulphur remaining in the naphtha. The problem was traced to the presence of elemental sulphur which forms on exposure to air, readily dissolves in the organic phase and is not distinguished by chemiluminescence.

The hydrogenated product reflects the paraffinic nature of the Stuart shale kerogen[10] with over 60 wt% paraffins, and approximately 20% wt of both naphthenes and aromatics. The level of aromatic saturation varied with space velocity and temperature.

Aspects of the analysis of the raw shale oils are made difficult due to their atypical physical properties, such as the concentration of hetero-atomic molecules, from those exhibited by petroleum crude oils for which many of the standard tests and correlations have been derived. The Oil Shale Industry will have to continue to develop its own data base and standard test methods.

Hydrotreating of Mid-Distillates

A series of fixed-bed hydrotreating tests were made to study the hydroprocessing performance of raw shale oils and shale oil/petroleum blends. The bulk of the testing was made at commercial-type hydroprocessing severities to generate data showing performance and product quality when hydro-processing shale oil mixtures with Australian petroleum liquids.

The properties of the hydrotreated products from a group of nine tests made with the 176–343°C shale oil produced under ATP heavy oil recycle blended at 10% with Australian FCC Light Cycle Oil (LCO) are shown in Table 7. Also shown in the Table are the products from three hydrotreating tests made with neat Arab Light Gas Oil (LGO); Australian FCC LCO; and a blend of LCO from FCC of petroleum oils and shale oil petroleum oil blends.

Of most importance is the similarity in product composition for the low level addition of shale oil to the petroleum feed to a LCO/LGO hydrotreater. The tests were made at varying hydroprocessing severities in the vicinity of those of Australian LCO/LGO hydrotreaters. The "average" severity of the tests consists of an average hydrogen partial pressure of 4200 kPa and a weighted average catalyst bed temperature of about 325°C. The "average" properties of the hydrotreated products from these tests compare well with those when hydrotreating neat Australian FCC LCO and virgin Arab LGO as exemplified in Table 8.

CO-PROCESSED SHALE OIL/GIPPSLAND FCC GASOLINE STABILITY

The heavy oil fractions of Stuart shale oil were subjected to fluid catalytic cracking (FCC) in order to assess the quality of the resultant FCC gasolines. Two FCC test campaigns were made: 1) an initial test made with 343°C shale oil produced with the ATP operated in the absence of heavy oil recycle and blended with Gippsland atmospheric resid; and 2) a second series of tests made with 343–510°C shale oil, produced with the ATP operated under conditions of heavy oil recycle, and blended with Gippsland atmospheric resid.

In the first campaign, eight FCC gasoline samples were consolidated into three composites to reflect varying organic nitrogen content: Sample A — low nitrogen content (< 9 ppm); Sample B — intermediate nitrogen content (147 ppm); and Sample C — high nitrogen content (380 ppm). The three FCC gasoline blends were derived from FCC operations carried out on the following feeds:

A: FCC of 100% Gippsland atmospheric resid.
B: FCC of a blend of 10% 343°C+ non-recycle shale oil and 90% Gippsland atmospheric resid.
C: FCC of 20% 343°C+ non-recycle shale oil and 80% Gippsland atmospheric resid.

Thermal stability was monitored by observing certain key physical properties, namely, ASTM Color and Sediment formation, during 90-day storage in air at 43°C storage temperature. Tests were made with and without the use of anti-oxidant inhibitors. For all of the tests made, Sediment never exceeded 5 mg/100 ml sample. There was a consistent trend of slightly increasing sediment and increasing discoloration with increasing nitrogen content of the respective FCC gasoline blends at the 90-day storage point. The use of anti-oxidant resulted in significant reductions in sediment formation for all three FCC gasoline samples.

In the second campaign, nine FCC gasoline samples were consolidated into four composites to reflect varying organic nitrogen content: A — 27 ppm N; B — 98 ppm N; C — 242 ppm N; and D — 4106 ppm N content. The FCC feed blends A,B, and C were made in the same proportions as in the first campaign, and sample D, a straight 343–510°C shale, added.

Thermal stability during 90-day storage in air at 43°C storage temperature was also monitored during the second campaign. Although the neat shale oil sample D experienced considerable sediment formation during the 90-day storage, the blends of shale oil/Gippsland material were very stable with sediment formation never exceeding 1.6 mg/100 ml, a good improvement on the oils made without heavy oil recycle to the ATP.

Whole Oil Hydrotreating

The bases for determining the required limit of hydrotreating of the whole shale oils are less well defined than for the individual cut due to the relatively even spread of the contaminants throughout the oil and differences in their specifications. The overall aim was still the production of a range of products acceptable to the local refineries as feeds. Typical quality requirements include:

1. Reduce metals to below 1 ppm wt.
2. Reduce Bromine Number to avoid gum formation.
3. Reduce carbon residues
4. Reduce total nitrogen content of the 340°C+ fraction to below that suitable for FCC feed.

Hydrotreating the highly unsaturated material which contains a higher metals content, relative to that of the lighter cuts of the whole oil required a two stage hydrotreating process. A guard bed and low pressure reactor in the first stage were primarily employed to reduce metals and Bromine Number. The second stage of hydrotreating was conducted at higher severities in order to study the reduction in nitrogen levels.

As can be seen from Table 9, the first stage product metals concentrations were below that required and the Bromine Number about half of the feed. Sulphur was reduced by about 60%, however concentrations of nitrogen and oxygen were affected to a lesser extent.

Heavy Gas Oil from the second stage represented a good FCC feed with nitrogen and metals below design limitations. Similarly the diesel cut with high Cetane Number and low nitrogen was an ideal base for transportation fuel.

Problems arise with the nitrogen levels in the product naphtha in the order of 200 ppm wt, which, without further hydrotreating, renders it unacceptable for gasoline reformer feed. Kerosene is similarly unacceptable with nitrogen and aromatic levels above standards.

Figures 4,5 and 6 indicate the effects of pushing the severity of the hydrotreater. Major improvements in naphtha and kerosene properties are achieved, but at significant cost penalties, both capital and operating due to a requirement for more catalyst, higher pressures, increased hydrogen consumption, and quality give-away in heavier products. An optional flow scheme would include hydrotreaters for the different products after achieving the required nitrogen content of the heavy fractions. Flow schemes to produce a syncrude were not considered in the proposed Stuart Development Project until stages 2 and 3.

Pour point of the hydrotreated whole oil was high at 10°C, but tests indicated that commercial depressants at a concentration of 2000 ppm wt were sufficient to reduce the level to 4°C.

Compatibility and Stability of whole shale oil

Compatibility tests were conducted with a 30% vol shale oil and a 70% vol mixture of typical petroleum crudes, representative of those used by probable downstream processors. Key properties were measured before and after designated periods. The full range raw whole oil and products form the two stages of hydrotreating were studied and no significant increase in particulates, asphaltenes, acidic components, or viscosity were reported.

Therefore shale oil was shown to be sufficiently compatible with the petroleum crudes used in the study to allow mixing, storage and transportation of these products without adverse effects.

Stability tests were conducted with the various cuts exposed to 100°C for 16 hours in an oxygen atmosphere. The results showed that shale oils are stable and that stability increased with the degree of hydrotreating. Mixtures of shale oils and petroleum crudes were tested with similar results.

CONCLUSIONS

Test programs have shown that the full range of shale oil products retorted from various Australian Tertiary oil shale deposits using different retorting technologies can be successfully hydrotreated using commercially available catalysts to provide high quality feeds to replace dwindling indigenous petroleum crudes supplies.

Co-processing of shale oil up to approximately 20% wt with petroleum gas oil fractions as FCC feedstock was successfully demonstrated, with product properties similar to that derived from the crude based blend stock.

The compatibility tests conducted as a part of upgrading studies indicate that coprocessing/ processing of shale oil syncrude should not cause major problems for Australian refiners. Commercial additives were demonstrated to have a beneficial effect on stability and pour point.

As the properties of oil derived from the different shale deposits varied, each hydrotreating requirement needs to be tailored to suit the specific market.

There is a definite cost penalty in processing shale oils relative to distillation and mild treatment of current feedstocks as primarily practiced in Australian refineries to date. However the costs of finding new reserves are increasing as are capital costs of refining the more abundant heavy sour crudes. Therefore the niche for an oil shale industry is becoming more apparent and with the endeavours of the Companies, a viable industry will be in place in Australia before the next crude petroleum oil price rise.

ACKNOWLEDGEMENTS

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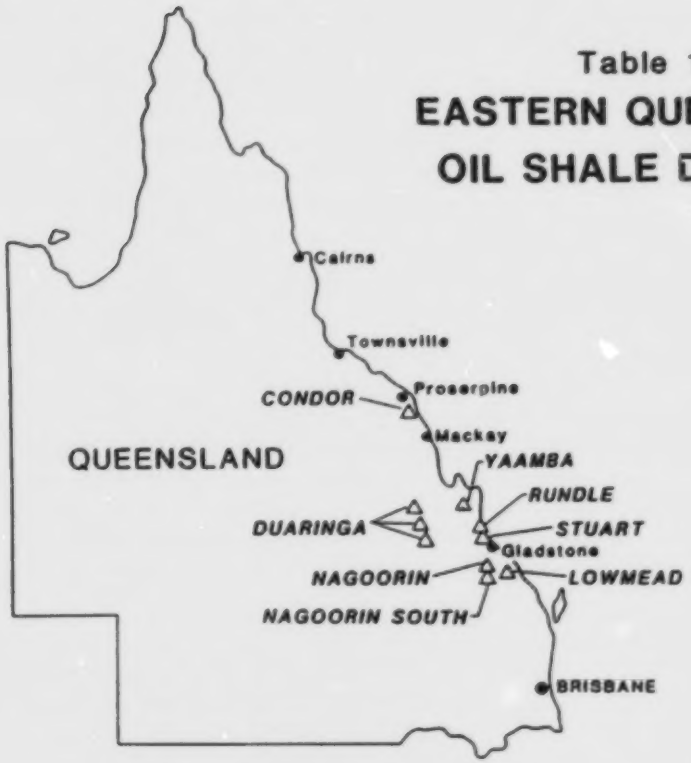


Table 1
EASTERN QUEENSLAND OIL SHALE DEPOSITS

DEPOSIT	INSITU RESOURCES	SPP/CPM INTEREST
CONDOR	9.65 billion barrels	100.00%
DUARINGA	3.72 billion barrels	100.00%
LOWMEAD	0.74 billion barrels	50.00%
NAGOORIN	2.65 billion barrels	50.00%
NAGOORIN SOUTH	0.47 billion barrels	100.00%
RUNDLE	2.65 billion barrels	50.00%
STUART	3.05 billion barrels	100.00%
YAAMBA	4.14 billion barrels	16.67%
TOTAL	27.07 billion barrels	20.60 billion barrels

TABLE 2.
STUART SHALE OIL PROJECT.
CRUDE SHALE OIL — CSO COMPARISON WITH GIPPSLAND AND SCO.

PROPERTY:		CSO	G'PSL'D	SCO
Boiling Range	°C	C4 – 510		
Specific Gravity	@ 15°C	0.819	0.7993	0.869
	°API	41.3	45.4	31.4
Elemental Analysis, %wt	Carbon	83.30		
	Hydrogen	12.00		
	Nitrogen	0.90	0.15	0.06
	Sulphur	0.43	0.1	0.15
	Oxygen/water	3.33		
Flash Point	°C	<20		
Pour Point	°C	3	15	
Ash	%wt	0.02		
Sediment	%wt	<0.01		
Con. Carbon	%wt	0.97		
Bromine No.		70		
Viscosity	cs @ 40°C (100°C)	2.69	2.03 (37.8°C)	
Metals, ppm wt	Sodium	3		
	Nickel	0.7		
	Vanadium	0.6		
	Arsenic	3.7		
	Iron	44		
	Lead	0.5		
	Copper	0.8		
	Aluminum	6		
True Vapour Press	psi	9.9		

Notes: G'PSL'D – represents typical Gippsland Crude[6]
SCO – represents synthetic crude oil[7] produced by Syncrude Canada Ltd.

TABLE 3
STUART SHALE OIL PROJECT. SHALE NAPHTHA — SN COMPARISON WITH GIPPSLAND AND SCO.

PROPERTY:		SN	G'PSL'D	HDT-SN	SCO
Boiling Range	°C	0–177	20–190	C4–177	C5–177
Yield on Crude	% vol	35.0	39.3		16.0
Specific Gravity	@ 15°C	0.777	0.732	0.73	0.722
	°API	50.6	61.6	62.3	64.4
Elemental Analysis, %wt	Carbon	84.90			
	Hydrogen	12.82			
	Nitrogen (ppm)	0.65		(<1)	(0.9)
	Sulphur (ppm)	0.35	0.03	(<1)	(5)
	Oxygen/water	1.28			
PONA, % wt (% vol)	Paraffins	25.6	59.1	60.5	(49)
	Olefins	32.6	0	0.5	
	Napthenes	13.0	32.5	20.0	(36.5)
	Aromatics	22.0	8.4	17.0	(14.5)
Phenols, Ketones, Alcohols		6.8			
Anilin? Point	°C	<20			
Bromine No.		95			0.4
Maleic Anhyd	Dienes	14.7			
Octane Micro Ron Clear		86		60	
Metals, ppm wt	Sodium	<0.5			
	Nickel	0.8			
	Vanadium	1.0			
	Arsenic	0.9			
	Lead	<0.2			
	Copper	<0.3			
	Aluminum	5			
True Vapour Press (RVP)psi			(10)		

NOTE: HDT-SN – represents typical hydrotreated Stuart Shale Naphtha.
G'PSL'D – represents typical Gippsland Crude[6]
SCO – represents synthetic crude oil[7] produced by Syncrude Canada Ltd.

TABLE 4.
STUART SHALE OIL PROJECT.
LIGHT SHALE OIL – LSO COMPARISON WITH GIPPSLAND.

PROPERTY:		LSO	G'PSL'D
Boiling Range	°C	177–233	190–230
Yield on Crude	%vol	14.5	7.1
Specific Gravity	@ 15°C	0.839	0.843
	°API	37.2	44.9
Elemental Analysis, %wt	Carbon	84.69	
	Hydrogen	12.11	
	Nitrogen	0.78	
	Sulphur	0.38	0.06
	Oxygen/water	2.04	
Flash Point	°C	70	
Pour Point	°C	<–20	–43
Ash	%wt	0.02	
Sediment	%wt	<0.01	
Aniline Point	°C	<20	
Aromatics	%vol		14.7
Bromine No.		69	
Maleic Anhyd	Dienes	10.5	
Viscosity	cs @ 40°C (100°C)	1.41	(1.44)

NOTE: G'PSL'D — represents typical Gippsland Crude[6]

TABLE 5.
STUART SHALE OIL PROJECT.
MEDIUM SHALE OIL-MSO COMPARISON WITH GIPPSLAND AND SCO.

PROPERTY:		MSO	G'PSL'D	SCO
Boiling Range	°C	233–343	230–340	177–343
Yield on Crude	%vol	25.5	23.1	46
Specific Gravity	@ 15°C	0.877	0.843	0.877
	°API	29.8	36.2	29.8
Elemental Analysis, %wt	Carbon	85.04		
	Hydrogen	11.95		
	Nitrogen	1.05		0.01
	Sulphur	0.37	0.08	0.04
	Oxygen/water	1.59		
Flash Point	°C	124		
Pour Point	°C	–5	–6	
Ash	%wt	0.02		
Sediment	%wt	<0.01		
Con. Carbon	%wt	0.11		
Aniline Point	°C	44.9		46
Bromine No.		52.6		1
Maleic Anhyd	Dienes	10.2		
Viscosity	cs @40 (100°C)	4.05	2.88	
Cetane Index			51.7	40

NOTE: G'PSL'D – represents typical Gippsland Crude[6]
SCO – represents synthetic crude oil[7] produced by Syncrude Canada Ltd.

TABLE 6.
STUART SHALE OIL PROJECT.
HEAVY SHALE OIL — HSO COMPARISON WITH GIPPSLAND AND SCO.

PROPERTY:		HSO	G'PSL'D	SCO
Boiling Range	°C	343–510	340–365	343+
Yield on Crude	%vol	17.5	27.4	36
Specific Gravity	@ 15°C	0.912	0.868	0.943
	°API	23.6	31.5	18.6
Elemental Analysis, %wt	Carbon	85.66		
	Hydrogen	11.64		
	Nitrogen	1.17		0.15
	Sulphur	0.40	0.16	0.34
	Oxygen/water	1.13		
Flash Point	°C	>100		
Pour Point	°C	32	51	
Ash	%wt	<0.01		
Con. Carbon	%wt	0.38		
Ramsbottom Carbon	% wt		0.3	0.3
Aniline Point	°C		100.7	63
Bromine No.		33		
Viscosity	cs @ 40 (100°C)	25.4	(4.06)	
Metals, ppm wt	Sodium	1.8		<1
	Nickel	0.1	0.1	
	Vanadium	0.2	0.2	<1
	Arsenic	<2		
	Iron	3.3		<1
	Lead	<0.2		<1

NOTE: G'PSL'D – represents typical Gippsland Crude[6]
SCO – represents synthetic crude oil[7] produced by Syncrude Canada Ltd.

TABLE 7.
AVERAGE PROPERTIES FOR HYDROTREATED FCC PRODUCTS.

Product Properties	10% Shale Oil/90% Aust.FCC LCO	Aust. FCC LGO	Arab LGO
API Gravity	30.8	30.2	36.6
Specific Gravity @ 15°C	0.872	0.875	0.842
% wt Hydrogen	12.44	12.70	13.94
% wt Sulphur	0.01	0.01	0.05
Nitrogen, ppm	96	59	53
50% TBP Point, C	286	287	307
Watson "K" Factor	11.45	11.42	11.97

TABLE 8.
PRODUCT ASSAYS OF HYDROTREATED SHALE OIL/PETROLEUM BLENDS.

FEED TYPE	COLOR	BASIC N ppm	S.G.	ppm N	%S	D-2274 @ 95°C	
						0ppm	150ppm
A	1.0	47	0.8708	76	0.01	13	<1
A	2.0	126	0.8740	207	0.02	<1	<1
A	1.5	16	0.8702	77	0.02	40	<1
A	1.0	15	0.8676	67	0.01	9	<1
A	1.0	16	0.8665	51	<0.01	15	7
A	1.5	31	0.8735	75	0.01	4	7
A	1.0	16	0.8724	68	<0.01	<1	2
A	1.0	114	0.8827	193	0.02	<1	7
A	1.0	31	0.8676	53	<0.01	2	11
B	2.5	16	0.8751	59	0.01	<i	<1
C	1.5	16	0.8418	53	0.05	5	1
D	1.0	16	0.8702	47	0.02	<1	2

Feed Type: A: 10% wt 177–343°C Stuart Shale Oil/90% wt Australian FCC LCO.
B: Australian FCC LCO
C: 233–343°C Arab LCO
D: 32% wt FCC Stuart Shale derived LCO/68% wt Australian FCC LCO

Notes:
1. All samples tested less than 2 ppm wt Arsenic.
2. All Bromine Numbers were less than 2.0.
3. Average hydrotreat pressures 4200 kPa.
4. Stuart shale oil is used throughout these tests.
5. D-2274 test work results in mg/100 mL. 0& 150 ppm refer to anti-oxidant dosages.

TABLE 9.
WHOLE OIL HYDROTREATING RESULTS CONDOR SHALE.

PROPERTY		FEED	1ST STAGE PRODUCT	2ND STAGE PRODUCT
HDT PRESSURE			MODERATE	HIGH
WABT °C			LOW	MODERATE
Specific Gravity	@ 15°C	0.867	0.860	0.831
	°API	31.7	33.0	38.8
Elemental Analysis, %wt	Nitrogen	0.90	0.83	0.063
	Sulphur	0.35	0.12	0.001
	Oxygen	0.95	0.68	0.027
Pour Point	°C	4	13	10
Ash	%wt	0.013	<0.001	<0.001
Bromine No.		50.0	17.1	0.9
Carbon Residue	% wt	0.64	0.11	<0.01
Metals, ppm wt	Arsenic	2	0.4	<0.05
	Iron	13	0.7	<0.1

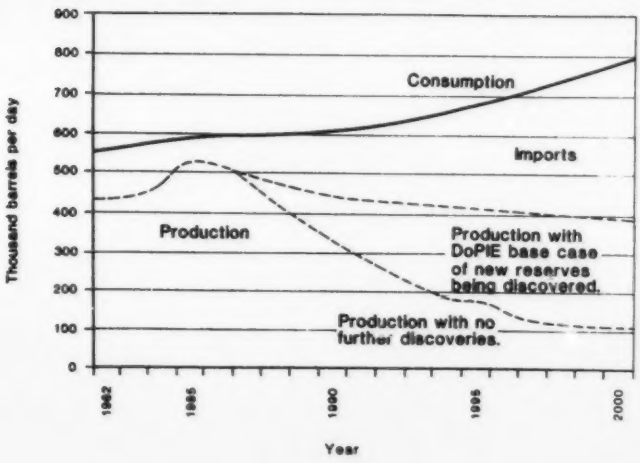
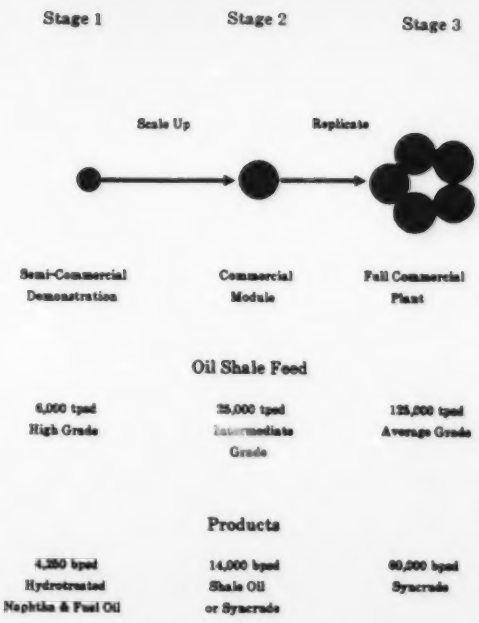


Figure 1 AUSTRALIAN OIL SUPPLY AND DEMAND



PROPOSED STUART DEVELOPMENT PLAN

Figure 3

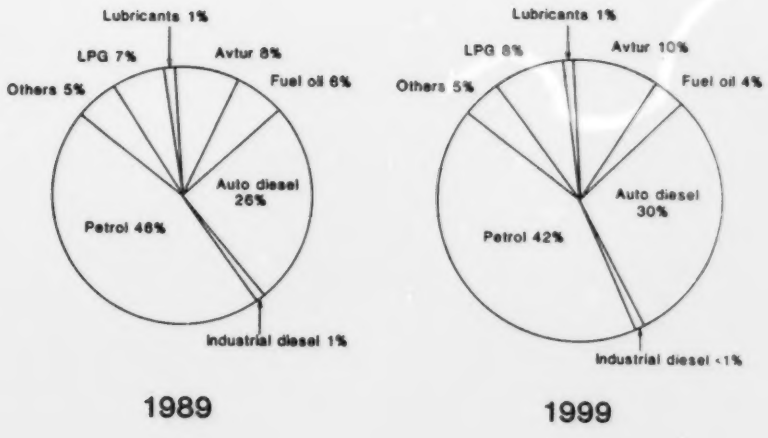


Figure 2 PRODUCTS CONSUMPTION COMPARISON

Source : AIP, Petroleum Gazette, Vol. 26 No. 3, p10.

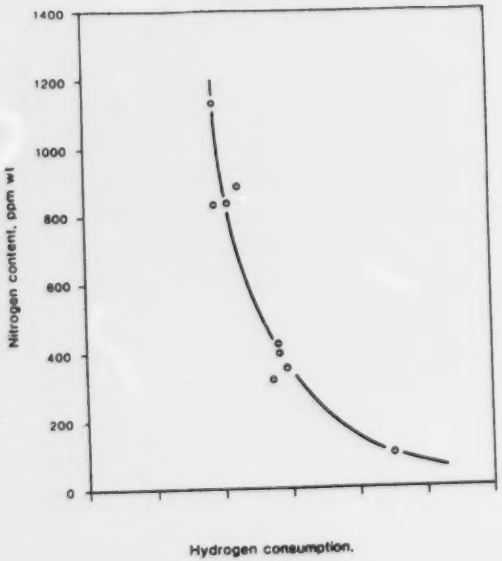


Figure 4 HYDROGEN CONSUMPTION IN SECOND STAGE HYDROTREATING vs NITROGEN CONTENT

Whole Oil Hydrotreating - Condor Shale Oil

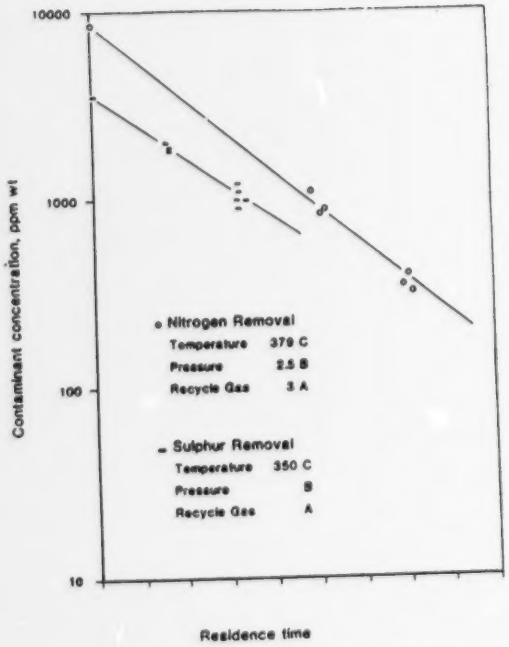
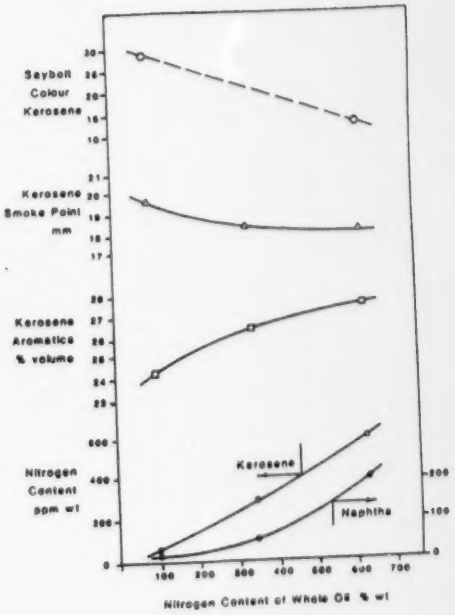


Figure 5 FIRST ORDER KINETIC PLOT FOR SULPHUR AND NITROGEN REMOVAL

Whole Oil Hydrotreating - Condor Shale Oil



VARIATION OF NAPHTHA AND KEROSENE PROPERTIES WITH WHOLE OIL NITROGEN CONTENT

Figure 6

Future Synthetic Crude Oil Quality

T.J. McCann, Vice President, RTM Engineering Ltd.

Abstract. New heavy crude upgrading projects are selecting higher quality synthetic crude oil objectives than presently practiced. This paper presents preliminary results from a study for AOSTRA in defining appropriate quality targets for synthetic crude oil for upgrading R and D planning in the later 1990's.

The study is based on projections of refinery configurations and product demands, quality and quantity, in areas readily accessible from Alberta's heavy crude and bitumen regions. Changes are expected in a variety of product specifications due to environmentally related pressures. These, along with changes in crude availability and product volume demands, will lead to revision in refinery processing, feeding back to appropriate targets for S.C.O. quality. Also, different markets are envisaged for incremental S.C.O.'s as production expands and the role of such S.C.O.'s in refinery crude slates is examined. Surveys of existing and future producers and users are being used to assist in the analyses leading to the proposed targets.

The new S.C.O. targets should prove useful to AOSTRA and others as reference points for primary and secondary upgrading research and development.

1. INTRODUCTION

On this 15th anniversary of AOSTRA, I am very pleased to have been asked to discuss future synthetic crude oils (S.C.O.). This paper is based on the work to date on a study for AOSTRA, including surveys of selected S.C.O. marketers, users, potential users and process licensors.

AOSTRA upgrading studies to date have used quality specifications developed 8 to 10 years ago and an update is needed to reflect changes on the demand side since that time, and as projected for the future.

Many speakers and papers over the years have commented on the lack of residual conversion facilities in Canadian refineries compared to those in the U.S. But such comments overlook the very appreciable coking and now residual hydrotreating facilities in Canadian "upgraders". When these facilities are added to those in Canadian refineries, the overall capabilities are quite similar. Upgraders are an integral portion of Canada's refining industry.

2. UPGRADERS

Heavy crude oil and bitumen upgrading is generally assumed here to be the processing necessary to allow that heavy crude or bitumen to be pipelined to and then processed in a conventional light and medium crude refinery.

The "first" upgrader, that of Unocal at Santa Maria, California, produces and pipelines in a dedicated line a coker distillate to be further processed in Unocal's Rodeo refinery 350 kilometres away. The Rodeo refinery itself processes significant quantities of heavy crude oils so that it does not readily fit our definition of a light and medium crude refinery. I should also note that the Santa Maria plant also produces asphalt today although originally (1955) the asphalt refining was several miles away.

Unocal and Suncor operations continue to be based on delayed coking while Syncrude uses the more severe but higher liquid yielding fluid coking process with the recent addition of a portion of residual quasicatalytic ebullated bed hydroprocessing.

The Coop Upgrader, originally the NewGrade project, came on line in late 1988 but has had teething problems - process and mechanical - which are just being resolved. The "upgrader" feeds the original conventional refinery units with intermediate fractions produced in excess of refined product production needs sold as S.C.O. This "upgrader" was designed for a lighter heavy crude diet than Syncrude or Suncor, with intermediate fractional qualities meeting those of low sulphur Alberta light crudes. With all residue passing through fixed bed catalytic hydroprocessing with significant conversion, this facility represents a departure in Canada.

Husky's Lloydminster upgrader project has broken ground for an ebullated bed hydroprocessor based facility which will also process distillates from the nearby asphalt refinery. As at Coop, the residual conversion facility is backed up by a delayed coker which processes unconverted material from residual hydroprocessing. Again product quality will be well above current practice - near those of conventional light crudes.

OSLO has selected a very high conversion, two stage residual hydroconversion approach.

The existing upgraders have usually operated to maximize production and this has resulted in quality variations batch to batch and over time, due to variable operation in both primary and secondary units including catalyst activity and selectivity, declines with time. These quality variations have often been as great a concern to refiners as the "abnormal" qualities of current S.C.O. fractions themselves.

3. SPECIALTY S.C.O.'S

The survey results to date strongly indicate that there will be very few, if any, new refinery units specifically built to process S.C.O. This means no new S.C.O. refineries, such as Shell Scotford, or major new S.C.O. processing facilities, such as those at Petro Canada in Edmonton.

This is not to rule out specialty S.C.O.'s such as the high naphtha content S.C.O. being considered by Canadian Energy in its coal-oil coprocessing or premium distillate/asphalt blends discussed at the 1987 AOSTRA Conference. Suncor has long sold special blends of individual S.C.O. fraction as well as railway diesel. But there is a growing consensus that incremental S.C.O.'s will be predominantly ones that are very similar to, or even enhance, Alberta light crudes.

In this paper, we consider only non specialty S.C.O.'s incremental to current or announced production. But upgrader proponents, especially those pushing smaller scale ventures, should look very closely at specialty markets.

4. INCREMENTAL MARKETS

Outside Alberta, only the Sarnia Suncor refinery is a major S.C.O. user at 15 percent to 20 percent of the total. Shell Scotford and Petro Canada and Esso in Edmonton account for over 60 percent of current S.C.O. consumption. Various other refineries, from Chevron in Vancouver to United in Warren, Pennsylvania, use the remainder, seldom more than 4 percent of the total S.C.O. production.

For Alberta refineries, there will be sufficient conventional light crude and current S.C.O.'s for the foreseeable future. However, the decline in Alberta light crude availability will necessitate Ontario refineries finding alternate sources. Contrary to other forecasters, we do not see any worldwide shortages of light crude through 2005, hence, believe the Ontario challenge is only in developing pipeline access to foreign light crudes and/or enhanced use of new S.C.O.'s. If concerns develop regarding Ontario access via U.S. Gulf coast to Chicago pipelines, this may mean Portland to Montreal to Ontario routing via existing pipelines. In any case, Ontario will have access to foreign light crudes. Quebec refineries will continue to have access to foreign crudes and will at some point add Hibernia crude availability.

Declining U.S. domestic light crude production is necessitating more use of imported light crudes in the Chicago area. The Montana to Denver region has also been noted by survey respondents as having major potential for enhanced Canadian light crude imports. Some U.S. northwest potential was also noted, along with Vancouver.

The light crude demands in the directly accessible Ontario and Chicago areas alone are well over 1,500,000 BPD. A new 100,000 BPD upgrader - equal to about 2 years decline in Alberta light crude production - would satisfy less than 7 percent of such markets.

As well, other U.S. midwest areas are prime candidates. The U.S. Rocky Mountain area presents a unique but much smaller opportunity although the pipeline juggling needed would also provide access to Turbo at Calgary. Montreal and Washington State refineries may also provide good market prospects.

At this time, we are inclined to assume only modest, long term increases in overall crude demand in most S.C.O. market areas. But even using 1989 demands and a very conservative 10 percent market penetration, 250,000 BPD of incremental S.C.O. markets appear available. With good quality S.C.O., the penetration could well reach twice this level, spread over roughly 20 refineries, many already using conventional Alberta light crudes.

5. PRODUCT PRESSURES

Refiners are currently trying to guess at the outcome of a very wide range of regulatory initiatives and, in the case of gasoline quality, to preempt a few of these. In many cases, scientific bases for the various initiatives are not well defined and "political environmental control" approaches are being discussed in overly simplistic terms - "solutions", usually without regard to impacts of other initiatives. Here we will note the issues without discussion except where appropriate to S.C.O. qualities:

(a) GASOLINES

RVP Reduction. Canadian provinces have agreed to reduce to a 10.5 PSI level this year. Although legislation lags badly, refiners may proceed with that level anyway in the hope that they can head off a move to a lower level later. This initiative is important in three ways:

a) Pressure to get butane down in S.C.O.
b) Pressure to keep C5C6 content of S.C.O. low.
c) Slightly increased crude demand that results from backing out butane.

Mileage Controls. Within the next year, there will likely be new car mileage standards imposed due to greenhouse gas - principally - CO2 concerns. This will reduce gasoline consumption in future. Gasoline taxes will go up, probably dramatically, in both Canada and the U.S. (Toronto has proposed a 10 cent a litre tax.) This will promote smaller engines and less gasoline consumption.

Clean(er) Gasolines. Gasoline formulations producing fewer exhaust emissions are under extensive study but implications with respect to S.C.O. are now undefined. Aromatics and light olefins in gasolines will be under special scrutiny.

(b) JET FUEL – KEROSENE TYPE

While not now produced from S.C.O., most people talked to believe that future S.C.O.'s must be suitable for Jet A production.

Smoke Point (or equal spec) – While some relaxation is allowed today, RTM foresees a 20 mm minimum standard prevailing in the future.

Aromatics – Again, the current specification relaxation is expected to disappear in the early 1990's and a 20 percent maximum used. This could well be lowered late in the decade.

Sulphur – A move to a 0.05 wt percent sulphur level can be expected when the same specification for diesel is in place.

(c) DIESEL FUELS

Aromatics/Cetane – While the U.S. EPA appears likely to hold (for now) to the current 29 to 30 percent U.S. average aromatics level, California will move to 10 percent or equivalent emissions (20 percent for small refiners). U.S. and Canadian pressures to move towards the California level are expected, at least to 20 percent, with a corresponding cetane increase to 43 cetane number. (The EPA is still using cetane index, overstating the quality of some U.S. diesels.)

End Point – Again, pressures to a lower level are evident due to higher emissions with high end points. (Buses are already on kerosene for smoke control.)

Sulphur – A Canadian move to a 0.05 percent level is expected late this year or early next year for implication by about 1994. Note that this move will likely impact offroad vehicles and railroads.

Mileage – Mileage standards in some form are coming. Taxes will go up (but have less sales impacts than for gasoline).

(d) LIGHT FUEL OIL

In Canada light fuel oil sales are important only in Ontario, and even in the U.S. there is limited segregation of light fuel oil from diesel, so that the above diesel comments are appropriate.

(e) HEAVY FUEL OIL

Sulphur – New federal/provincial/international SO_2 protocols will be in place in 1991 and already there are moves to lower levels.

We could spend this whole conference discussing "environmental" and related issues that will be challenging refiners over the next decade. The above are only a few areas of concern, generally ones impacting on S.C.O. qualities.

6. PRODUCT SALES TRENDS

Table 1 presents recent U.S. government forecasts of changes in domestic refined product sales.

In most U.S. and Canadian areas of interest, we anticipate the following:

a) Gasoline Sales

Constant to slightly declining gasoline sales are predicted after 1995 due to new mileage standards and higher taxes, partly offset by slightly lower volumetric efficiency due to lower specific gravity of "clean" gasolines and added oxygenate use.

b) Kerosene Jet Fuel

An increase at the 1.5 percent to 2.0 percent per year level are forecast until 1995 and then sales will tend to level out as the number of flights are controlled at many airports and as more efficient engines predominate.

c) Diesel

As truck mileage increases at about the same rate as the GNP, sales will continue to climb with some offset from more efficient engines. Despite improved efficiencies, railway use is likely to rise slightly in volume terms due largely to lower volumetric energy content due to increased desulphurization.

d) Light Fuel Oil

Continuing slow declines or static markets can be expected in both Canada and the U.S.

e) Heavy Fuel Oil

Demand is already very low in all incremental S.C.O. market areas except the U.S. west coast and Quebec. Added hydro power availability should drop Quebec consumption from recent peaks.

Thus, a gradual decline is predicted in all areas in the G/MD ratio where G = motor gasoline + aircraft gasoline (very minor) + Jet B (minor military use only) + naphtha specialties and MD = Jet A + kerosene + diesel + light fuel oil. This ratio is important as it provides important clues as to the appropriate composition of incremental S.C.O.'s. As the demand for middle distillates rises, higher diesel fraction yields can be built into the S.C.O.

Figure 1 presents past and projected G/D ratios for domestic sales in Ontario and western Canada. The quite different recent trends in these regions is apparent but in both regions the G/D will decline. The U.S. midwest G/D ratios tend to be even higher than those of Ontario, but as Table 1 shows, even there the G/MD ratio will decline with time. The western border states have patterns similar to western Canada, i.e. low ratios.

Generally in the U.S., the sales of jet fuel and light fuel oil are higher than in Canada. As Table 1 indicates, the diesel portion of the total "distillate" sales is increasing in the U.S., requiring higher quality basestocks - if current quality levels are to be maintained.

7. SURVEY CONCLUSIONS

The following conclusions are becoming apparent from the survey and analytical work to date:

(a) No new units will be built at refineries specifically for other than special S.C.O.'s.

(b) New S.C.O.'s will be used incrementally to other light crudes — at 5 percent to 20 percent (occasionally as high as 25 percent) of total crude charge.

(c) New S.C.O.'s will generally be coprocessed with other light crudes.

(d) New S.C.O.'s will be processed outside the Prairies and some pipeline contamination will occur.

(e) There will be definite preferences for premium bottomless S.C.O.'s that can be moved through IPPL line #1 as far as Superior.

(f) New S.C.O. fractions must process "equivalent" to conventional light crude oil fractions in conventional refining units — i.e. refinery intermediates from S.C.O. when blended with similar materials from conventional light crudes must require no special operating conditions or produce intermediates or products that have significantly poorer quality characteristics.

(g) Sulphur in middle distillate fractions will seldom be of major concern as total hydrotreating of all middle distillate fractions will become the refinery norm.

(h) Any residual fractions should have equal or better characteristics than those of Alberta light crude residual fractions — i.e. they should be processable in catalytic cracking units with light crude residual capabilities.

(i) Test results now reported are unlikely to be fully appropriate to know whether (f) has been achieved — especially relative to catalytic cracking, middle distillate cetane improvement/aromatic saturation (generally new to refiners) and to a lesser extent naphtha denitrogenation and gas oil hydrocracking. Special pilot and/or full scale test runs will be needed to confirm relative processability for all new S.C.O.'s. (Such tests are also needed to confirm refinery planning models which have had trouble with current S.C.O.'s.)

(j) Some overspecification of certain characteristics will likely continue for some time to preclude major refinery problems.

(k) Refiners want a consistent quality S.C.O. — they have problems whenever quality varies batch to batch.

(l) There will be markets for large quantities of S.C.O. meeting the above criteria.

(m) Naphtha and gas oil fractional yields should be near those of conventional light crudes.

(n) There will be a significant preference for higher middle distillate yields than from conventional crudes in western Canada and northern states, BUT such a bias will not be pronounced in the U.S. mid west and Ontario until beyond 2000. (Note that imported light crudes tend to have higher middle distillate yields than North American light crudes.)

(o) Fractional yields, however, will not be as important as fractional properties given the low concentration planned in crude change.

New S.C.O.'s appear likely to be priced about the same as Alberta light crudes corrected for reduced residual content. Some premium may be paid as experience is gained in their use and premium properties are identified. At this time we doubt their being priced at marginal crude value, even when that is above their value assuming 100 percent of charge. Perhaps in time that will change.

8. DRAFT S.C.O. SPECIFICATION

Table 2 is a preliminary version of a new S.C.O. standard for AOSTRA planning purposes. Several items of clarification are in order relative to the preliminary specification proposal:

(a) Gas Oil Yields – Refineries are operating gas oil conversion facilities, catalytic crackers and hydrocrackers at over 30 percent on crude charge to product gasoline components and precursors. Such utilization will continue, especially in Ontario and the U.S. midwest, for many years. If insufficient gas oil is available in the crude, conversion of heavy diesel fractions will become necessary but in the case of

catalytic cracking, this leads to poorer quality diesel due to byproduct light cycle oil production. Refiners with hydrocrackers, however, will not be particularly impacted as heavy diesel conversion is now common.

(b) Cetane Number – 80 percent to 90 percent of light cycle oil from catalytic cracking is blended after desulphurization with virgin middle distillates to produce a common diesel/light fuel oil product. The remainder is blended with virgin stocks for segregated light fuel oil (primarily in the U.S.). As even hydrotreated light cycle oil from S.C.O. has a cetane number of only 25 at best, the 20 percent or so of light cycle oil pulls down diesel cetane appreciably. Hence, the diesel fraction of S.C.O. should have a cetane above the final product specification.

(c) Aromatic Saturation and Cetane Improvement – Saturated aromatics — naphthenes — do not have as high a cetane (or smoke point) as do equivalent boiling paraffinic fractions. Thus, S.C.O. middle distillates do not have the same potential for cetane (and smoke) improvement as do the same fractions of conventional light crudes. The total of aromatics and naphthenes is very important when further improvement in cetane and smoke point is considered.

(d) Crackability – Simple yet appropriate quality parameters need to be defined for gas oil to reflect "equivalent crackability". To date, no agreement or consensus has been noted in this regard.

Generally, this specification accommodates the survey responses and concerns noted to date. There is still appreciable leeway in the specification but we would be surprised not to see special specifications, outside the limits of Table 2, apply to certain S.C.O. or S.C.O. fraction transfers to specific refiners.

9. IMPLICATIONS FOR UPGRADING

While there has been much talk of actual integration of upgrading and refining operations, the early conclusion of this work indicates that future upgraders will be required to provide S.C.O.'s that mimic conventional light crudes in processing.

In some cases, upgrading proponents – project and process – will need to undertake appreciable test work to convince refiners that their S.C.O. is coprocessable with conventional light crudes.

TABLE 1
U.S. FORECASTS REGARDING
CHANGES IN SELECTED PRODUCT DEMANDS
% per annum

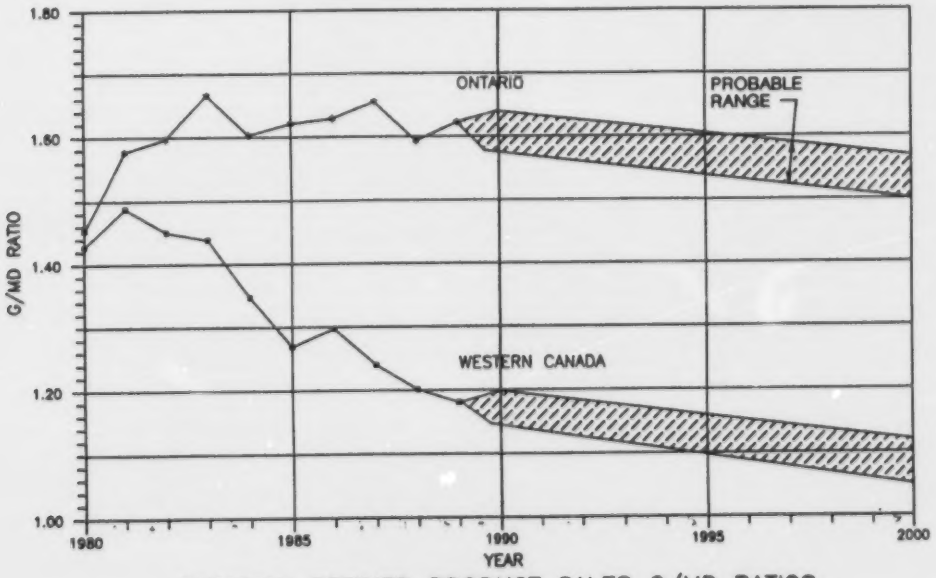
	FORECAST OF OCTOBER 1988	FORECAST OF OCTOBER 1989
Period Covered	1989 to 2000	1990 to 2010
Motor Gasoline	+0.2	+1.0
Distillate - Total - Diesel (Transportation)	+1.1 +1.9	+1.1 +2.0
Jet Fuel	+1.7	+1.8

Bases: Low crude price forecast cases presented in

Energy Information Administration Annual Energy Outlook, 1989 to 1990

TABLE 2
PRELIMINARY PROPOSED NEW
S.C.O. SPECIFICATION

FRACTION	QUALITY	UNITS	MIN.	MAX.	NOTE
C3 minus	Yield	Vol%	--	Nil	
C4's	Yield	Vol%	1	3	Isobutane preferred
C5 to 180°F	Yield	Vol%	--	6	
180° to 350°F	Yield	Vol%	16	23	
(Heavy Naphtha)	Sulphur	ppm wt	--	500	
	Nitrogen	ppm wt	--	2	
	Naphthenes +2 x Aromatics	Vol%	50	--	
350° to 450°F	Yield	Vol%	15	--	
(Kerosene)	Smoke Pt	mm	20	--	
	Aromatics	Vol%	--	20	May drop to 18 by 2000
350° to 650°F	Yield	Vol%	30 *	36 *	
(Diesel)	Cetane	Cetane No.	43	--	
	Aromatics	Vol%	--	30	New test needed
	Sulphur	ppm wt	--	5000	
650° to 1000°F	Yield	Vol%	30	35	
(Gas Oil)	Sulphur	ppm wt	--	6000	
	Nitrogen - Total	ppm wt	--	1000	
	Nitrogen - Basic	ppm wt	--	250	
	Aromatics or Hydrogen Content	Vol% wt%	-- 12.5	50 ? --	Other "better" parameter(s) may emerge - such as UOPIK
	Metals Ni + V	ppm wt	--	2	
1000°F Plus	Yield	Vol%	--	6	0 preferred
(Residuum)	Metals	ppm wt	--	3	
	Sulphur	ppm wt	--	1000	
	Carbon Forming	CCR wt%	--	10 ?	Depends on volume present



CANADIAN REFINED PRODUCT SALES G/MD RATIOS
FIGURE 1

Demonstration Of The High Conversion CANMET Hydrocracking Process On Cold Lake Vacuum Residuum

B.B. Pruden, A.K. Jain, G. Muir and K. Fernie

Abstract. This paper describes commercial experience with the CANMET Hydrocracking Demonstration Plant, and in particular a recent rest run with Cold Lake Residuum.

Integrated into Petro-Canada's Montreal Refinery, the Demonstration Plant has a nominal capacity of 5000 BPSD. It features additive preparation, a single stage hydrocracking reactor, product let-down, fractionation and gas cleanup. The CANMET Hydrocracking Process utilizes a low-cost additive to obtain high conversion of residuum to light products.

The test run with Cold Lake residuum was partially funded by AOSTRA as part of its upgrading demonstration test program.

Background (1971–1988)

The CANMET Hydrocracking Process for upgrading heavy oil and refinery residua has been available for licensing as a commercially proven process since 1987. The nature of the underlying process chemistry and the relationships among the process variables had been developed by over 50,000 hours of pilot plant operations at Energy Mines and Resources (EMR) and at Petro-Canada Research and Development. A typical pilot plant (Figure 1) used for this fundamental research has a reactor having a diameter of 6 cm and length of 4 meters. These pilot plants are suitable for research and development and for predicting the operating characteristics of proposed feedstocks. Based on the positive pilot plant results achieved up to 1981 at EMR, the technology was acquired by Petro-Canada and the CANMET Hydrocracking Technology Group consisting of personnel from Petro-Canada and Partec Lavalin was formed with an objective of proving the viability of the process on a commercial scale. It was decided that a CANMET Hydrocracking Process Demonstration Plant with a nominal capacity of 5000 BPSD would be constructed at Petro-Canada's Montreal East Refinery. A schematic diagram of the Demonstration Plant is shown in Figure 2. Choice of the Montreal location was based on the existence of a suitable infrastructure of utilities, offsites, product and hydrogen supply. The main limitation of this location is that overall refinery economics dictate the crude oil to be refined and hence the type of VTB feed available to the Demonstration Plant. Since startup in October, 1985 the Demonstration Plant has processed mainly Interprovincial Pipeline (IPL) vacuum residue which is considerably more refractory than either Cold Lake VTB or Arab Light VTB which were the design feeds. Nevertheless comparison of Demonstration Plant operations with pilot plant testing of IPL-VTB confirmed that pilot plant data could be used to predict commercial operation. In October 1987 a quantity of Cold Lake feed became available for a 12 day test as reported in the paper "Upgrading of Cold Lake Heavy Oil in the CANMET Hydrocracking Demonstration Plant" presented at UNITAR IV, Edmonton, August 1988. Even though the feed quantity was limited and it was contaminated by less reactive IPL VTB the test was a major success in proving that higher conversions could be obtained from more reactive feed.

One significant result of Demonstration Plant operation was a decision, in 1986, to adopt a single component additive, iron sulphate, instead of the coal/iron sulphate used in the pilot plant runs.

By the end of 1987 the key process features were demonstrated and the process was deemed to be ready for commercial licensing. The Demonstration Plant was then available for process optimization and to achieve long term objectives such as, run length, metallurgy evaluation etc. This program had achieved the following by late 1988:

1. Continuous runs of up to 9 months duration. (Refinery operating constraints unrelated to the Demonstration Plant prevented longer runs. Without these limitations run lengths of at least two years would be expected.)
2. Conversion of 65 wt% with IPL feedstock.
3. An excellent correlation between pilot plant and Demonstration Plant operation allowing high conversion commercial scale operation to be accurately predicted.

4. The inherent safety and reliability of the CANMET Hydrocracking Process during several major refinery upsets.
5. Effectiveness of single component additive in maintaining over two years of coke-free operation.

Key Features of CANMET Hydrocracking

The heart of the CANMET Hydrocracking Process is the reactor which operates at 820–850°F and approximately 2000 psia. The reactor is a vertical bubble column having feedstock and hydrogen rich recycle gas enter the bottom and all products and spent additive exit at the top. At reactor conditions thermal cracking and hydrogenation are the main reactions and coking is the side reaction. A proprietary additive prepared from iron sulphate is used to promote hydrogenation and effectively eliminate coke formation.

The additive prevents coking in two ways; chemically by promoting hydrogenation of coke forming free radicals and physically by interfering with the growth and coalescence of coke precursors. The presence of these coke precursors, called "mesophase", can easily be determined by microscopic examination of the reactor liquid phase. This analytical method can be used by the operator to set temperature and additive rate so as to ensure coke-free reactor operation. The effectiveness of the dual-role additive permits the use of operating temperatures which give high conversion in a single stage reactor. Therefore if multiple reactors are required for large capacity plants, they are arranged in parallel. During process upsets where feed and/or hydrogen flow to the reactor is interrupted the additive continues to prevent coking and the reactor can be held at a temperature a few degrees below normal until operation is restored.

The quality of the naphtha, distillate and gas oil products from CANMET Hydrocracking of heavy hydrocarbon residues is superior to products from coke rejection processes, however they still require further hydrotreating. In a typical refinery scenario it is expected that these products will be hydrotreated, in existing units, prior to blending in finished products or routing to further upgrading processes. For a grass roots scheme capital and energy savings can be achieved by integrating hydrotreating reactors into the CANMET Hydrocracking Process.

A typical CANMET Hydrocracking Process Unit will therefore consist of additive preparation, reactor(s), heat exchange, products let-down and separation, fractionation and hydrogen management facilities.

Test Program for 1989

The CANMET Hydrocracking Technology Group has a continuing program to update and improve the data base. For 1989 it was decided that proven performance data, on Alberta heavy oils/bitumens, would be obtained for the iron sulphate additive in the pilot plant and for high-conversion operation at the demonstration plant. The following two tests were scheduled:

1. Pilot plant testing of Athabasca bitumen VTB at the EMR pilot plant near Ottawa. The test was to utilize the iron sulphate additive and the primary objective was to operate for 30 days at a minimum conversion of 90 wt% to verify that the previous data based on coal/iron sulphate additive was repeatable using iron sulphate alone.
2. A high conversion test run at the Montreal Demonstration Plant with the objective of operating at a minimum conversion of 90 wt% following which the conversion would be raised to the maximum practical level until all of the Cold Lake VTB was used. AOSTRA was a financial participant in this test which was monitored by AOSTRA representatives.

Both tests were conducted in April/May 1989 and all objectives were achieved. Highlight of each test are presented in the following sections.

Pilot Plant — Athabasca Bitumen Test Run

The pilot plant test run was scheduled to operate for 30 consecutive days on Athabasca VTB feedstock at a minimum conversion of 90 wt% using the commercial additive. In preparation for the test Athabasca whole bitumen from Syncrude/Alberta Research Council was distilled to produce the required amount of VTB. The content of 975°F+ fractions in the VTB was approximately 90 wt%.

Feed was introduced to the Bells Corners Pilot Plant on April 13, 1989. Steady state operation at the target conversion of 90 wt% was confirmed on April 17 and the test run continued until May 17. The daily conversions for the 30 day period are shown in Figure 4. Average for the 30 day period was 90.4 wt%. Daily samples of reactor liquids were analyzed for the presence of mesophase (coke precursors). During the entire test run no mesophase was observed in the reactor indicating that the CANMET Hydrocracking process could operate indefinitely at these operating conditions.

Three sets of complete material balance and product quality data were taken during the test run. Table 1 gives the average yields, sulphur and nitrogen conversion and chemical hydrogen consumption.

Demonstration Plant — Cold Lake Test Run

The Demonstration Plant test programs started with the acquisition and delivery of almost 400,000

bbl of Cold Lake Crude/diluent blend. This was delivered via the Interprovincial Pipeline System to the Montreal Refinery in five batches in March 1989. These batches were processed in one atmospheric and distillation unit and the vacuum residue was stored in the CANMET Hydrocracking feed tank. Despite all efforts to maintain pure Cold Lake feed, the resulting feedstock was contaminated with approximately 25% IPL-VTB as shown in Table 2. The test run proceeded with this feedstock with the knowledge that operating conditions would be different than those required to process 100% Cold Lake VTB feed.

The test run feed was introduced April 12 and ran through mid-May. During the first week a new additive grinding mill was being commissioned. Mechanical problems with the drive system prevented use of this mill during the test run although data collected during this period indicated that significant savings in additive usage would have been achieved using additive prepared by this method. However the actual test run started on April 20 using the dry-grind additive mill which has provided trouble-free service for approximately two years. The test run consisted of three distinct periods as follows:

1. The unit was lined out at conditions expected to produce 90% conversion for pure Cold Lake VTB and held at steady state for five days. During this period a full set of material balance and product quality data were taken. These results showed clearly that the feedstock was less reactive than pure Cold Lake VTB. Conversion for this period was 85%.
2. Unit conditions were adjusted to values which would result in 90% conversion for the actual feedstock and the unit held at steady rate for five days while data were collected. The data confirmed the 90% conversion. Since the performance of the unit indicated that higher conversion could easily be attained, it was therefore decided to raise conversion to the maximum practical level.
3. Pitch conversion was raised by slowly increasing reactor severity. The limiting conversion was reached when the pitch product pump performance was impaired by high solids content. Severity was then adjusted until pitch pump performance was satisfactory. This operation was deemed to be the maximum practical conversion and the unit was lined out at these conditions and kept at steady state for fifteen days. Average conversion was 93.5 wt% with smooth trouble free operation throughout this period.

Figure 4 shows the daily pitch conversion achieved between April 12 and May 14. Following the initial period of erratic results caused by the commissioning of the new additive grinding mill the conversion data is smooth and consistent.

The variation in daily average reactor temperature is presented in Figure 5. During all three test run periods the reactor temperatures were very steady with maximum deviation from the daily average of not more than 1°F. Table 3 gives the hydrogen consumption, conversion of sulphur and nitrogen and product yields for each of the test run periods.

Following the test run the Demonstration Plant was shut down for inspection of the reactor and other vessels. The vessels were clean with no evidence of significant coking. The reactor had been in operation since April 1988 during which time the Montreal Refinery had undergone a number of severe upsets including a seven hour total power failure and utilities failure. Even these severe upsets to the CANMET Hydrocracking Unit resulted in no coke deposition.

Demonstration of Reactor Stability

The CANMET Hydrocracking reactor is a vertical cylindrical pressure vessel with minimal internals. Hot VTB feed and hot recycle hydrogen enter at the bottom. A small flow of cold hydrogen is added as side quench at two specific elevations on the reactor. The liquid phase inside the reactor is thoroughly back-mixed so that in normal operation the reactor is essentially isothermal. Due to the presence of the CANMET Hydrocracking additive the reacting mixture is thermally stable to the extent that interruption of Demonstration Plant oil and gas feeds lasting several hours have been experienced without any temperature excursions.

On May 11, whilst operating at about 93 wt% conversion, the reactor stability was demonstrated to a group representing a potential client. One of the side quench hydrogen streams was suddenly reduced to minimum flow. This change produced a short duration rise in reactor temperature of less than three Fahrenheit degrees. The other quench stream automatically compensated and the temperature returned back to normal within 30 minutes as shown in Figure 6. This procedure was repeated by reducing the other quench flow to a minimum and the result was similar. This demonstration of reactor stability will apply to any feedstock and at any conversion level.

Summary

The two successful test runs described in this paper confirm the commercial readiness of the CANMET Hydrocracking Process and establish new performance milestones. The results of both tests are in accordance with the results predicted using the CANMET Hydrocracking data base prior to the tests. Effectiveness of the iron sulphate additive in

upgrading of Athabasca VTB has been demonstrated by the pilot plant test. Commercial scale conversion of up to 94 wt% was achieved in a single reactor during the Demonstration Plant test with a Cold Lake VTB/IPL VTB blend. High conversion operation was maintained at steady state for extended periods limited only by feedstock supply in both tests.

With the completion of these tests the effectiveness and operability of the CANMET Hydrocracking Process has been thoroughly demonstrated. No further Demonstration Plant test runs are planned for 1990. Pilot plant testing can be used to predict the performance of commercial reactors in future residue or heavy oil upgrading projects.

TABLE 1
Pilot Plant Athabasca VTB Test Summary of Product Yields
(Average for 90wt% Conversion)

Pitch Conversion wt%	90.0
Sulphur Conversion wt%	69.1
Nitrogen Conversion wt%	26.7
Hydrogen Consumption SCF/BBL (fresh feed)	1695.0
Hydrogen Consumption wt% (fresh feed)	2.4
Product Yields (vol% of fresh feed)	
Butanes	3.35
Naphtha (C5–204C)	24.17
Distillate (204–343C)	36.02
Gas Oil (343–524C)	33.93
Total Liquid Products (C4–524C),vol%	97.47

TABLE 2
Demonstration Plant Cold Lake Test Feedstock Properties

	Pure Cold Lake from Data Bank	Feed for the Test	Pure IPL from Data Bank
API Gravity, °API	3.1	4.4	9.8
Specific Gravity	1.052	1.041	1.002
Viscosity			
cst @ 135°C	1080		110
cst @ 150°C	490		63
Toluene Insolubles,wt%	0.13	0.2	–
Asphaltenes, wt%	20.4	15.5	12.7
CCR, wt%	24.0	20.6	18.3
Ash, wt%	–	Nil	–
Elemental Analysis, wt%			
Sulphur	6.0	5.14	2.7
Nitrogen	0.6	0.62	0.4
Carbon		83.0	
Hydrogen		10.52	
Oxygen		0.69	
Metals, wwpm			
Ni	130	80	28
V	320	170	130
Fe	20	60	10
524°C+, wt% by Dil60z	90	87	83

TABLE 3
Demonstration Plant Cold Lake Test Typical of Product Yields

Survey Period	April 20–24	April 25–29	May 1–3
Pitch Conversion, wt%	85.0	90.0	93.5
Sulphur Conversion, wt%	61.8	66.3	70.3
Nitrogen Conversion, wt%	31.0	35.7	40.9
Hydrogen Consumption SCF/BBL	1128	1405	1713
Hydrogen Consumption wt%	1.64	2.05	2.50
Product Yields, vol% of Fresh Feed			
Butanes	3.62	3.91	4.16
Naphtha(C5–204°C)	22.03	25.14	27.70
Distillate(204–343°C)	34.43	37.29	39.80
VGO (343–524°C)	32.19	31.18	30.46
Total Distillate Yield C4–524°C, vol%	92.27	97.52	102.12

SCHEMATIC OF CANMET HYDROCRACKING PILOT PLANT

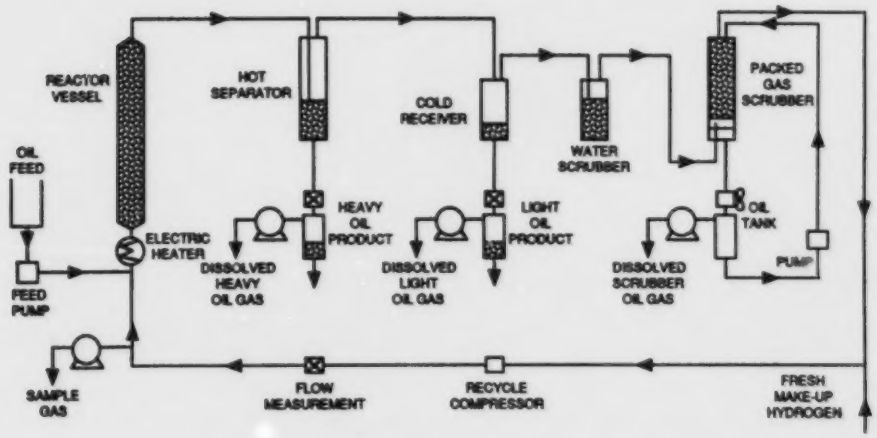


FIGURE 1

SCHEMATIC OF CANMET DEMONSTRATION PLANT

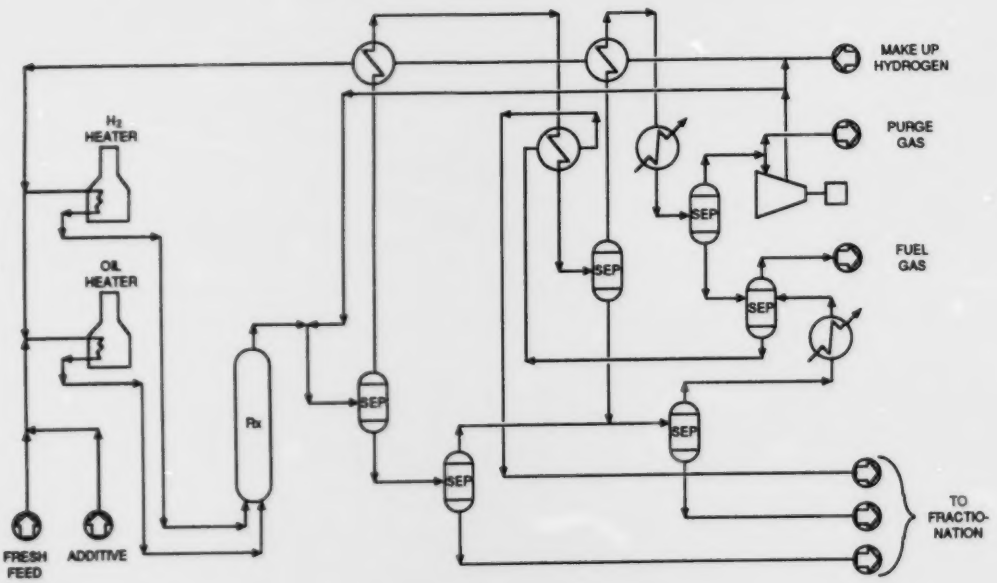


FIGURE 2

CANMET HYDROCRACKING

PILOT PLANT ATHABASCA VTB TEST
WT % CONVERSION OF 975° F+

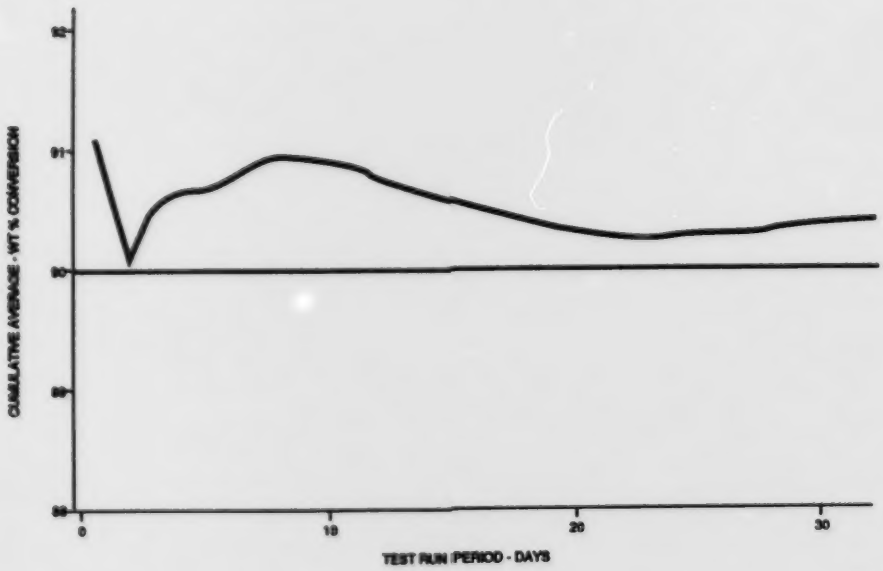


FIGURE 3

CANMET HYDROCRACKING

DEMONSTRATION PLANT COLD LAKE TEST
DAILY AVERAGE PITCH CONVERSION

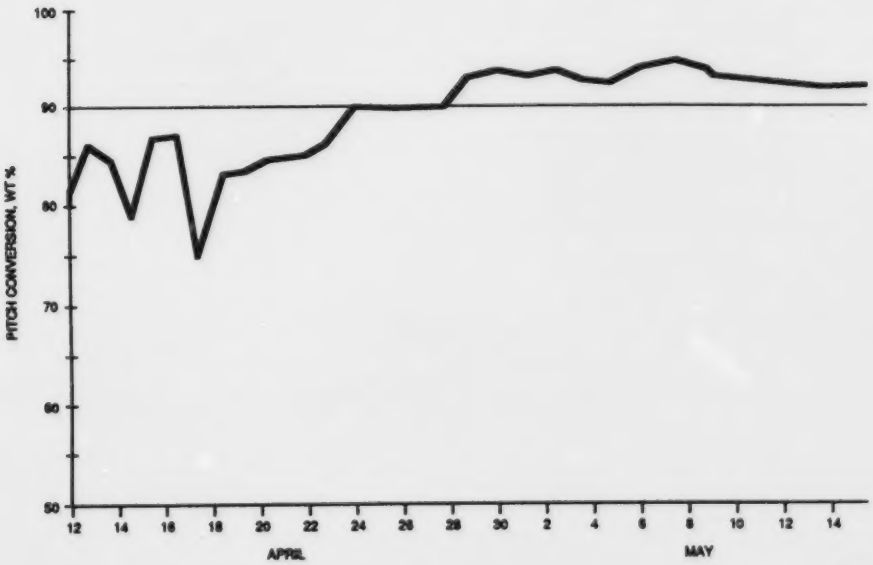


FIGURE 4

CANMET HYDROCRACKING

DEMONSTRATION PLANT COLD LAKE TEST
DAILY AVERAGE REACTOR TEMPERATURE

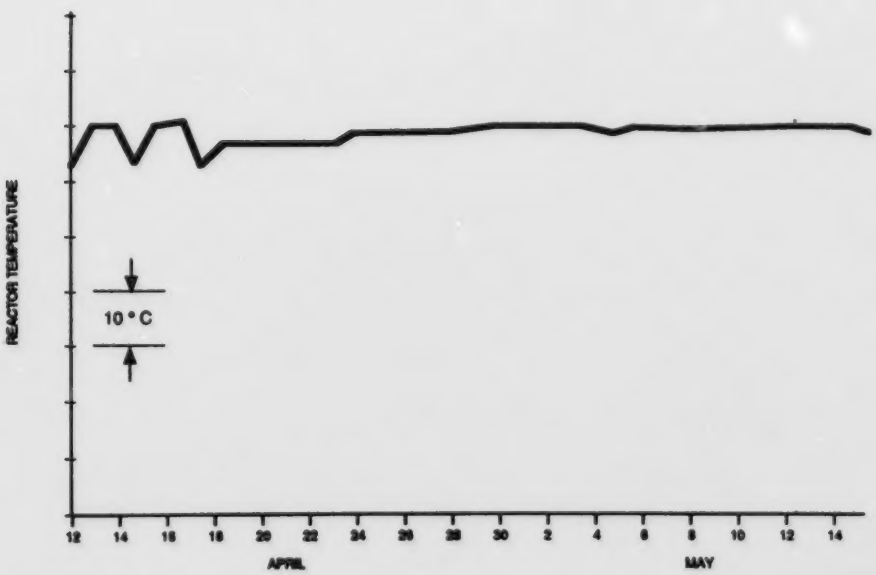


FIGURE 5

CANMET HYDROCRACKING

REACTOR STABILITY DEMONSTRATION

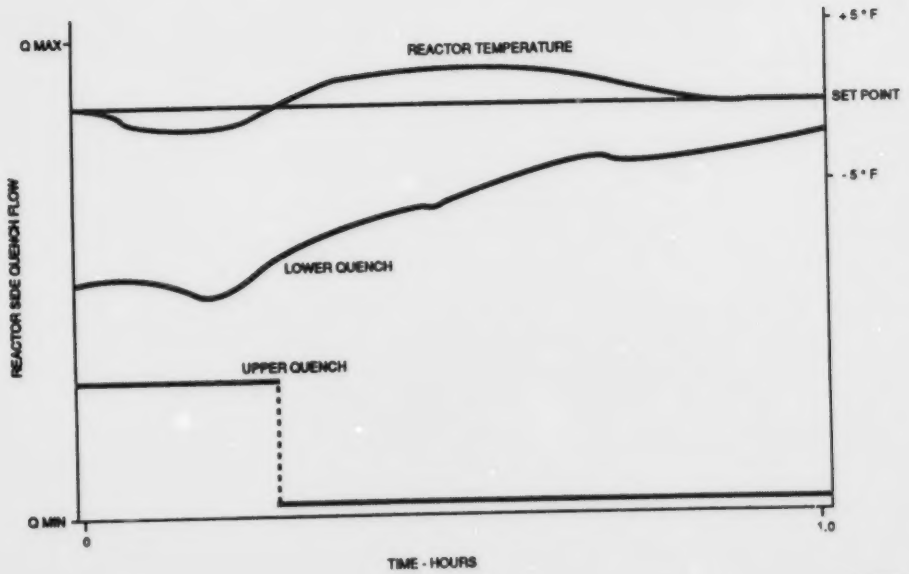


FIGURE 6

The Kearl Lake Pilot: Striving To Be Number One In Athabasca In Situ Recovery

D.H. Burger, Senior Staff Engineer, Husky Oil Operations Ltd., and K.E. Kisman, Principal Reservoir Engineer, Alberta Oil Sands Technology and Research Authority

Abstract. At least 83% of the bitumen in place in the Athabasca Oil Sand deposit must be recovered by in situ methods due to overburden depths being too deep for surface mining methods. This reserve of approximately 118 billion cubic meters (743 billion barrels) of bitumen in place represents a formidable challenge.

In 1979, CDC Oil & Gas Limited (now Canterra Energy Ltd., a subsidiary of Husky Oil Ltd.) and Tenneco Oil of Canada Ltd. initiated a modified steam drive pilot in the Athabasca deposit. The Alberta Oil Sands Technology and Research Authority (AOSTRA) joined the piloting effort in 1983. Esso Resources Canada Limited's involvement in the pilot began in March 1989, soon after its purchase of Tenneco's interest in the lease.

Effective, hot interwell communication was achieved by hori- zontal fracturing followed by a combination of hot water and steam injection. Further refinements of the process have subsequently been undertaken to shorten the time to achieve hot communication, increase bitumen production rates, and reduce steam-oil ratios.

This paper briefly reviews the pilot's history and operating procedures, and discusses its accomplishments. The success of the pilot is evidenced by the production of its one-millionth barrel of bitumen in November 1989.

INTRODUCTION

Alberta's Energy Resources Conservation Board has estimated (Report No. ERCB ST89-18) that nearly 141.8 billion cubic meters of bitumen (53% of Alberta's total bitumen in place) is located in the Wabiskaw-McMurray formations in the Athabasca area (Figure 1). About 117.8 billion cubic meters (83%) of the Athabasca crude bitumen are estimated by the ERCB to be located outside the area which can be exploited by surface mining, and must be recovered by in situ methods. Recovering this resource represents a formidable challenge because of the high viscosity of the bitumen (>1,000,000 mPa.s at reservoir conditions) and the lack of formation energy combined with very complex geology.

In 1979 CDC Oil & Gas Limited (now Canterra Energy Ltd., a subsidiary of Husky Oil Ltd.) and Tenneco Oil began pilot operations aimed at developing an in situ bitumen recovery process in Oil Sands Lease T87 in the Kearl Lake area of the Athabasca deposit. The location of this pilot in relation to other pilots and commercial projects in the Fort McMurray area is shown in Figure 2.

Figure 3 shows the lease in more detail. It comprises 76 sections, mostly in Townships 95 and 96, Range 7, W4M. This figure also shows the location of 188 test holes drilled to evaluate the lease. In the northern half of the lease the overburden is thin enough to permit surface mining. In the southern half of the lease, in situ recovery will be required. The total bitumen in place has been estimated to be 1.7 billion cubic meters (10.7 billion barrels), divided almost equally between the mining and the in situ areas. The pilot site is located near the centre of the in situ area in the corner of sections 9, 10, 15, and 16, Township 95 Range 7 W4M. At the pilot site the overburden thickness is in the order of 150 m (500 ft.).

PILOT OBJECTIVES

The pilot objectives which are discussed in this paper include:

1. Evaluate the use of horizontal hydraulic fractures to develop injector to producer communication;
2. Optimize steam injection rates;
3. Maximize bitumen recovery;
4. Assess the areal and vertical distribution of heat in the reservoir;
5. Evaluate the performance of wellbore and surface equipment; and
6. Determine key performance parameters such as bitumen production rates (CDOR), steam-oil

ratios (SOR), water-oil ratios (WOR), and gas-oil ratios (GOR).

HISTORY OF THE PILOT

Construction of the pilot began in the first quarter of 1980, and startup of the first pattern began on December 12, 1981. In February, 1983, the Alberta Oil Sands Technology and Research Authority (AOSTRA) joined the project team.

The original layout of wells and facilities is shown in Figure 4. This figure shows three different types of wells grouped into an 'A' pattern and a 'B' pattern. Each well is identified by a name that consists of two letters followed by a one or two digit number (e.g. AP1). The first letter designates the pattern ('A' or 'B'). The second letter designates the type of well: 'P' for production, 'I' for injection, or 'O' for temperature observation. The number is the well number for that type of well.

The 'A' pattern was a 2.17 ha (5.37 acre) inverted 7-spot pattern with peripheral steam injection. The purpose of the peripheral injection was to isolate the pattern from the surrounding reservoir. The 'B' pattern, as originally drilled, was a 1.09 ha (2.69 acre) inverted 5-spot pattern surrounded by eight steam injection wells. It was decided to delay startup of the 'B' pattern until some operating experience had been obtained on the 'A' pattern.

As a result of 'A' pattern experience, changes were made to the 'B' pattern prior to its startup in February 1985. The main concern about the 'A' pattern was the large volume of steam that was lost from the pattern because of the injection into the peripheral wells. This lost steam represents a high cost and causes a very high steam-oil ratio. Therefore, it was decided not to inject steam into the peripheral wells at the 'B' pattern. The pattern was also converted from a 5-spot to a 9-spot (Pattern B11 in Figure 5), in order to better capture condensed steam and mobilized bitumen, and in order to recover the bitumen in the pattern in less time. Two of the peripheral injection wells were later utilized for steam injection when the 'B' pattern was expanded in 1987. Figure 5 shows the current wells and pattern configurations.

'A' pattern steam injection was shut-in in September 1986 in order to save fuel costs. Despite the lack of steam injection, production from three 'A' pattern wells has continued.

Startup of patterns B18 and B19 occurred in September 1987. In 1988 a high rate steam injection test was conducted on the 'B' patterns. In 1989 Esso Resources Canada Limited purchased Tenneco's interest in the lease and the pilot, a confidential test to control steam outflow from the 'B' patterns was initiated, and the one-millionth barrel (158,910 m^3) of bitumen was produced on November 23, 1989. We understand that this production is far higher than has been achieved by any other in situ pilot in the Athabasca bitumen deposit.

A bar chart showing most of the important milestones for the pilot is given in Figure 6.

RESERVOIR DESCRIPTION

At the Kearl Lake pilot the McMurray Formation has been subdivided into both stratigraphic and reservoir units. Stratigraphically, the McMurray Formation is divided into lower McMurray unit sediments comprised of an upward fining fluvial sand sequence, middle McMurray unit sediments comprised of a series of stacked upward fining tidal channel sequences, and upper McMurray unit sediments comprised of a coarsening upward marine silty sand sequence. The thickness of the lower McMurray sediments is controlled by the structure on the unconformity surface of the underlying Devonian limestone. The fluid movement within the reservoir sands has been vertically bounded by the impermeable, underlying limestone and by the overlying shale and sandy-shale sequences of the top of the middle McMurray, and the upper McMurray units.

In the pilot area, two distinct reservoir zones were designated as the lower and middle zones, which approximately correspond to the lower and middle McMurray stratigraphic units. Further divisions within each zone were assigned to identify discrete layers within the reservoir.

Both the stratigraphic and reservoir units are shown in Figure 7, which is a copy of the logs for the type well BO4. Note that the lower and middle reservoir zones are usually separated by a non-reservoir shaly unit, which is the preserved "abandonment" phase of the lower McMurray unit fluvial sequence. This unit has proven to be only a partial barrier to the upward movement of hot water and steam.

Within the upper section of the middle reservoir zone is found a transition zone from low to higher water saturations (up to 0.60), as shown by the resistivity log trace in Figure 7. In the middle reservoir zone are also found channel breccias, usually associated with the base of individual tidal channel sequences. The channel breccias show considerable variation in clast size (1 to 15 cm), as well as wide variation in the clast to sand matrix ratios. In some wells these breccia intervals appear to retard vertical fluid movement, and have been identified as the possible cause for poor bitumen production in several wells.

FACILITIES

Surface facilities are typical of most thermal recovery pilots. They consist of steam generating facilities, production treating facilities, and oil storage and truck loading facilities. The steam generating facilities have a proven capacity of slightly more than 1500 m^3/d of 80% quality steam at a pressure up to 10,000 kPa (1450 psig). The

production treating facilities are capable of handling more than 1000 m^3 of produced fluids.

Fresh water is produced from the lower McMurray unit in the mining area of the lease by two water wells located in 1-18 and 14-18-96-7 W4M, approximately 13 km (8 miles) from the pilot site. All produced water is disposed into the Methy Formation.

A typical production well completion is shown in Figure 8. This well is completed open hole in the lower zone, but most newer wells are cased throughout the entire McMurray formation as this anchors the bottom of the casing and prevents it from moving. Conventional bottomhole insert pumps are now being used in all production wells. Also note that a bubble tube and thermocouple have been strapped to the tubing of all production wells.

SAND CONTROL

Satisfactory sand control, which still permits good fluid inflow, has been achieved for the majority of production wells in the pilot. Highlights of the production well completions are as follows:

a) The wells are drilled and cased, or liner completed to 15 to 20 m below the base of the McMurray formation to provide a sump below the lowest producing interval in which the tubing and pump are landed;
b) Completion intervals are 3 to 5 m in length, and are located near the bottom of both the lower and middle McMurray zones; two intervals may be used within a zone if the original interval proves to be less productive than desired, or is isolated from the steam zone by a shaly interval; and
c) A sand retainment screen is set across each open interval in the well.

The most recently installed sand screens were sized on the basis of partial sand retainment, using the method described by George (1985). This sizing method works best when the production interval has been cored and sieve analyses have been conducted. For uncored wells, the gamma ray and formation density logs were compared to the logs from cored wells in order to infer whether the sand grains were larger, smaller, or comparable to those around the cored wells. This inferred size difference was used to adjust the screen opening size for the uncored wells.

The best results have been obtained using outside wire-wrapped screens. Inside wire-wrapped screens and Texaco sand filters (described by Toma et al, 1986) have also been tested. Texaco sand filters seem to have worked satisfactorily, but the wells in which they have been installed have had lower than average fluid production rates. The inside wrapped screens did not work satisfactorily for two reasons:

(i) During workovers the end of the tubing sometimes damaged the wrap or moved the screen and liner, by either snagging it on the way in, or becoming stuck due to inflowed silt packing the space between the tubing and screen (so that damage was caused by pulling it free); and
(ii) The space between the screen and outer mandrel tended to plug with silt and reduce the fluid inflow.

For one or both zones in many of the wells, the interval between the outside of the screen and the formation was packed with frac sand pumped downhole in a polymer-sand slurry. Although this "slurry pack" technique was successful, it has not proven to be more effective than a properly designed sand screen without a slurry pack.

Injection wells are cased through into the Devonian and cemented to surface. They have been perforated over one-meter intervals near the bottom of each zone, and the perforated intervals have been isolated by a thermal isolation packer. The completion intervals are not screened unless, after an injection shutdown, a workover has been necessary to remove sand and return the well to injection, at which time a screen is normally run.

STARTUP PROCEDURES

One of the most critical parts of the reservoir recovery process is the startup. The objectives of the startup are:

1) Develop a communication path within each zone between each injection well and the production wells around it (within practical limits, the lower in the zone the better); and
2) Heat the communication path slowly, so that it does not plug with cold bitumen;

Startup of the 'A' pattern and the 'B11' and 'B18' patterns were conducted using a "hot water startup procedure". The 'B19' pattern was started up using a "high rate steam startup procedure". The hot water startup process is considered the more conservative of the two procedures. It is used only for the lower McMurray zone when it is considered important to minimize the risk of breaching the shale unit between the lower and middle zones. For either startup procedure it is believed necessary to establish communication in the lower zone before the middle zone is started up. Otherwise, it is feared that the middle zone will act as a thief zone for most of the hot water and steam injected into the lower zone.

Communication is established relatively easily in the middle zone because of the overlying zone of high water saturation. The presence of this high water saturation zone is advantageous in that it provides a means of achieving interwell communication in the middle McMurray unit. However, the disadvantages are that considerable heat is often required to heat this non-productive zone, and it provides a path for hot water and steam to escape from the pattern (limiting the operating pressure and wasting heat).

The hot water startup procedure was improved with each startup. With the latest refinements, the procedure includes the following steps:

1) Completion of the bottom of the lower zone in both production and injection wells,
2) Steam stimulation of the production wells,
3) A high-rate water fracture of the injection well, and
4) Conversion of hot water to steam.

When the lower zone is sufficiently heated, then the middle zone is started up by completing the bottom of the middle zone in the production wells, steam stimulating them, then completing the bottom of the middle zone in the injection well(s), and starting steam injection.

Bottomhole pressure data obtained during the hydraulic fracturing operations in the lower zone, and observation well temperature data obtained shortly after the fracturing, indicate that the fractures were initially horizontal but rose towards the top of the zone. Tiltmeter data obtained during one of the hydraulic fractures indicated a complex fracture system with both horizontal and vertical components. The fractures did not stay open when the fluid injection rates were reduced to begin the next step in the startups. However, it is apparent that zones of higher effective permeability had been created throughout the regions penetrated by the fractures.

An indication of the improvements which have been made in the hot water startup procedure since it was first tested, starting in December 1981, is the reduction of the time required between the start of injection into the injection well and its conversion to 80% quality steam. This improvement in hot water startup time is shown in the following tabulation:

PATTERN	DATE STARTUP BEGAN	TIME BEFORE 80% STEAM QUALITY REACHED
'A'	December 1981	13 months
BI1	February 1985	5.5 months
BI8	September 1987	<2 months

The main reasons for these reductions in startup time have been the use of steam stimulations to heat up the production wells, improved monitoring techniques, and experience. This experience has permitted decreasing the number of temperature steps, and reducing the length of each step.

The high rate steam startup process differs from the hot water startup process in two ways:

(i) The production well stimulations are usually larger and start at higher rates (high enough to maintain a hydraulic fracture for several days before being cut back to a non-fracturing rate); and
(ii) The injection well is started up with a very high steam injection rate for several days (e.g. twice the rate used for the production wells); then for a few weeks is cut back to a rate which does not continue fracturing, but is still very high.

The advantages of the steam startup are that it is simpler and cheaper to implement, and it heats the reservoir faster. No hydraulic fracturing equipment is required, and the operators do not have to gradually adjust injection temperature, rates, steam quality, and so on. There should also be less cooling of production wells by the movement of cold water in the reservoir, and earlier bitumen production. The disadvantages of the high rate steam startup are a greater stress placed on surface and wellbore equipment and on reservoir caprocks, and a greater possibility of the fracture rising and penetrating into the middle zone. Which is the better startup process, is still under debate.

STIMULATIONS

As indicated in the previous section, steam stimulation of production wells has been an important part of the process of establishing hot interwell communication. Steam stimulations, to be successful in this pilot, have had to establish hot communication with the steam zone created around the steam injection well(s). Although some bitumen production resulted from the stimulation alone, satisfactory production rates did not occur until communication with the injection well(s) was established.

In this pilot there was very little attempt to determine how much bitumen production would result from steam stimulation alone without steam drive. However, there are some data such as the first month of the production period shown on Figure 9. This figure shows the bitumen and water production rates and the measured bottom hole temperatures for well BP10 during the first four months that it was on production. This well was on production for 13 days before steam injection started at the offset injection well BI9.

Initially, bitumen production was steady at an unsatisfactorily low rate. Injection started at well BI9 on 87-09-01, and soon caused an increase in the BP10 bottomhole temperature; but nearly three weeks elapsed before the bitumen production rate responded to steam injection. Following its response to steam injection, the bitumen production rate would have been quite satisfactory, if it had been maintained. However, the BI9 injection rate was reduced one month after its start up, and this caused a rapid decline in the bottomhole temperature at well BP10. The bitumen rate also declined to less than a satisfactory level by the end of the year. Thus, this stimulation is an example of a stimulation that was not successful.

An example of a successful steam stimulation is shown in Figure 10. Before the steam stimulation of well BP4, the bottomhole temperature and bitumen production rate were quite low. After the stimulation, the bottomhole temperature declined for some time,

then began to increase, indicating link-up with the steam zone around the injection well. Bitumen production rates also increased to a higher level after the stimulation, even though a slightly higher rate would be expected based on the response at other wells. It is believed that the reservoir around this particular well has an impediment to vertical flow of liquids; and that this impediment causes bitumen rates to be lower and more cyclical than for other wells with a similar pay thickness and temperature.

The volume of steam, injection rates, pressures, additives, etc. to use in any particular stimulation has been the subject of considerable work at the pilot, but more work is still required. Therefore, they will not be discussed further in this paper.

TECHNOLOGICAL ADVANCES

1. Bitumen Production and Steam-oil Ratios. The trends of average steam injection rates and bitumen production rates for the 'A' pattern are shown in Figure 11. In this plot the steam volumes are based on a consistent energy content of 2.4237 GJ/m^3 of cold water equivalent. This energy content assumes 80% quality steam at 8600 kPa (abs.) (300°C), relative to water at 10°C. Thus, the energy content of hot water and steam at various conditions is converted to consistent units for comparison.

During the balanced injection period, the injection rates into all injection wells (including the peripheral wells) were about the same. As can be seen by Figure 11, the highest production rates were achieved during this period. Communication had also been well established to all production wells (except to the lower zone of one well) by that time. Reservoir pressures in the steam zone were also much higher than at other times. However, the instantaneous steam-oil ratios were also high.

Figure 12 shows the trends of average injection rates and bitumen production rates for the combined 'B' patterns. The "high steam rate test" resulted in high bitumen production rates, and will be discussed in more detail later. Note that total steam injection rates were also nearly as high in other months, but the high injection rates in the other months were due to production well stimulations. The high bitumen production rates in 1989 are the result of another test that is still underway, and will not be discussed in this paper.

2. Interwell Communication. As pointed out earlier, very little bitumen production occurred in this pilot until good, hot interwell communication had been established. The Kearl Lake pilot demonstrated that effective interwell communication could be established over distances of at least 91.4 m (300 ft.).

Considerable improvements (ie. reductions) in the time and energy required to establish this communication were achieved with each successive startup at the pilot. These improvements can be demonstrated by a comparison of the cumulative bitumen production and cumulative steam-oil ratio plots for each pattern (Figures 13 and 14). In these plots the following patterns are compared: 'A' pattern, 'BI1' pattern, 'BI8' pattern, and 'BI9' pattern. In Figure 13, the cumulative bitumen production for each pattern is plotted on a per well basis. That is, in order to calculate the per well cumulative production, the monthly production of each pattern was divided by the net number of wells in each pattern: 6 for the 'A' pattern; 8 for the 'BI1' pattern prior to September 1987 (when the 'BI8' and 'BI9' patterns were started up), and 6.333 afterwards; and 2.833 for the 'BI8' and 'BI9' patterns. This method was used so that patterns having different numbers of wells could be compared.

Surprisingly, there is very little difference in cumulative bitumen produced between the 'BI1' pattern and 'A' pattern curves. However, it should be noted that the completion of the middle zones in the wells in the 'BI1' pattern was delayed for at least six months waiting on confirmation of continued funding. As expected, all curves demonstrate a significant increase in slope shortly after the completion of the middle zones. During the first 2.5 years, the cumulative bitumen production performances of both the 'BI8' and 'BI9' patterns is considerably better than that for both of the older patterns, largely because of better startup and well stimulation techniques.

A more significant difference between the 'A' and 'BI1' patterns is noted when comparing the cumulative steam-oil ratio curves (Figure 14). The 'BI1' startup used thermal energy far more efficiently than the 'A' pattern startup. Part of the difference of course is because the 'A' pattern was surrounded by steam injection wells, and most of the steam injected into these outside wells migrated away from the pattern. However, a further improvement is noted for the 'BI8' and 'BI9' patterns compared to the 'BI1' pattern. This improvement was likely the result of improved steam stimulations and the use of less hot water (none in the case of 'BI9'). Based on the 'BI8' and 'BI9' startup experience, it is believed that even further improvements can be made in the startup procedures.

3. Effect of High Steam Injection Rates. In late 1987,it was noted that the bitumen production rates of individual 'B' pattern wells were not as high as those achieved in 'A' pattern wells. It was also noted that the reservoir steam zone temperature, from which the steam zone pressure can be deduced, was lower in the 'B' pattern than it had been in the 'A' pattern. Therefore, a test was devised in which an attempt was made to increase the 'B' pattern steam zone pressure by increasing steam injection rates at the central injection wells.

The results of this test are shown in Figure 15.

Starting on May 5, 1988, the injection rates were increased by a factor of about 1.7. The reservoir pressure (as estimated using the peak steam-zone temperatures at well BO4) increased about 20% within one month of the start of higher injection rates, but then declined slightly and stabilized at about a 13% increase until the end of the high injection rate test on July 22, 1988. Then, when the injection rates were returned to their former levels, the reservoir pressure slowly declined to less than its pre-test level. The reservoir pressure did not increase as much as was expected because a large portion of the injected steam was migrating outside the pattern. Yet in spite of the smaller than expected increase in the reservoir pressure, the increase in the bitumen production rates (40% on average, with peaks over 50% above the original) was very encouraging.

FUTURE OBJECTIVES

Although this pilot has been successful, much work still needs to be done before the process technology will be sufficiently developed to begin a commercial project. The following work is proposed:

(i) A method for controlling steam outflow from the 'B' patterns is currently being tested. Initial results are very encouraging, even though it had been applied to only two sides of the pattern and part of the third. It is being expanded to enclose all of the 'B' patterns in 1990.

(ii) In recent months most of the steam injection has been into the middle McMurray zone. Later in 1990 the steam injection into the lower McMurray zone will be increased to determine its bitumen production capability.

(iii) Throughout the next period of operation, various analytical and numerical model studies will be carried out to improve our understanding of factors such as recovery mechanisms, optimum spacing, communication development, ultimate bitumen recovery, and so on.

The information from recent operating results and the above technology developments will be incorporated into a revised commercial plant feasibility study. This study will provide an estimate of the threshold crude price at which a commercial project can proceed and identify areas for further technological development which will reduce this threshold price.

In addition to the above, long term plans are to operate a prototype commercial project before proceeding to a commercial operation. However, these plans are on hold pending the required improvement in world oil prices.

CONCLUSIONS

1. The steam drive process applied at Kearl Lake has made significant progress toward commercialization of the Athabasca deposit. The pilot facilities and operating procedures have worked well. Good bitumen recovery rates have been obtained, and the recent steam-oil ratio is good, although the cumulative steam-oil ratio is still high due to early pilot operations.
2. The Kearl Lake pilot has produced more than 1,000,000 barrels of bitumen, which is more than that from any other in situ pilot in the Athabasca deposit.
3. The startup procedures have been successful in achieving communication between almost all injector-producer well pairs.
4. Steam stimulations alone have provided little bitumen production, but they are required in conjunction with injection well fractures to achieve good interwell communication.
5. Horizontal fractures tend to migrate toward the top of the zone.
6. Although sand control has been a concern in other Athabasca pilots, sand control methods used at the Kearl Lake pilot have been quite effective.
7. High steam injection rates significantly increased oil production rates, but did not improve the steam-oil ratio.
8. The lack of horizontal confinement due to a high water saturation region at the top of the middle McMurray zone limits the pilot pressure and temperature, and results in significant heat loss. A recent field test of a method to mitigate the problem has provided very good results.

ACKNOWLEDGEMENTS

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Toma, P., D.B. Livesey and T.R. Heidrick, "A New Sand Control Filter for Thermal Recovery Wells", Paper No. SPE 15057, 56th Calif. Regl. Mtg. at SPE, Oakland, Ca., Apr. 1986.

Figure 1: Major Oil Sands Deposits of Alberta

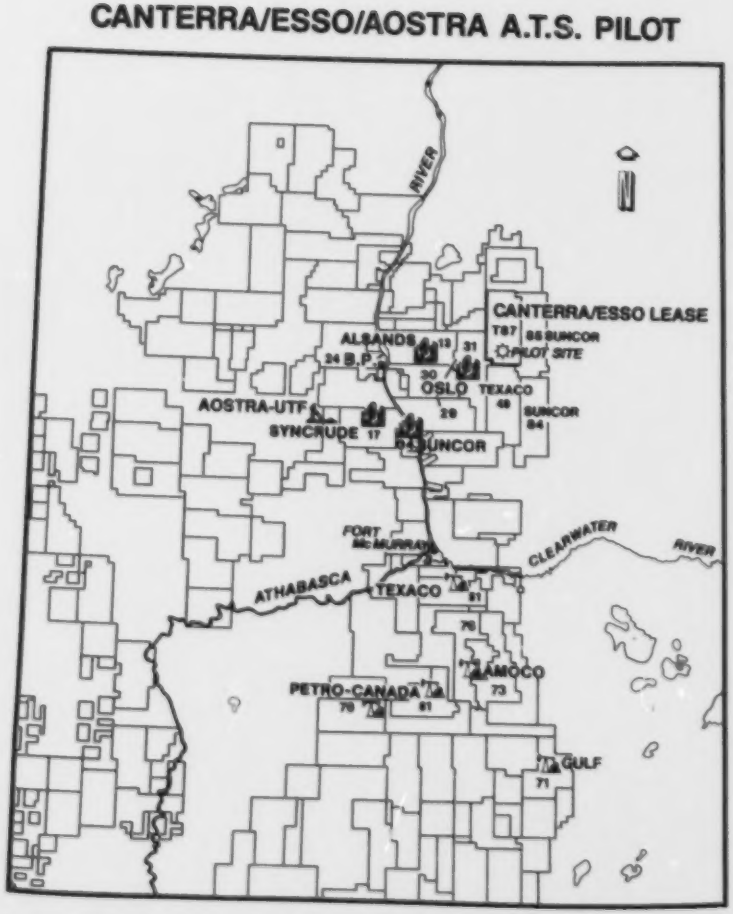

Figure 2: Athabasca Oil Sands Lease (Kearl Lake Area) and some other Projects (Existing and shut-down) in the Athabasca Deposit

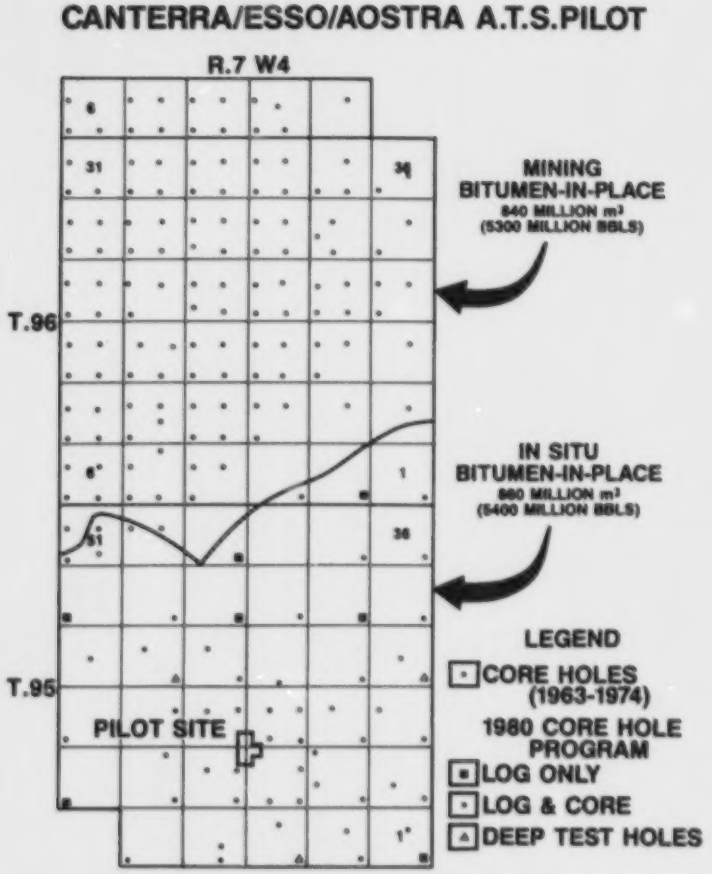

Figure 3: Athabasca Oil Sands Lease (Kearl Lake Area) Showing Core Holes and Pilot Site Location

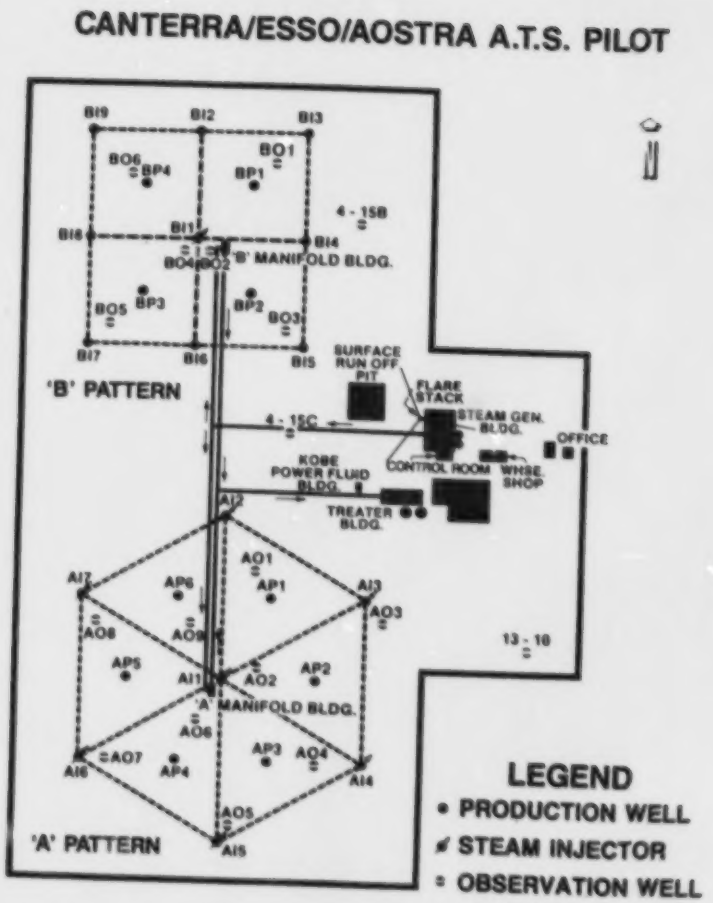

Figure 4: Layout of Wells and Facilities at the Beginning of the Pilot Operations

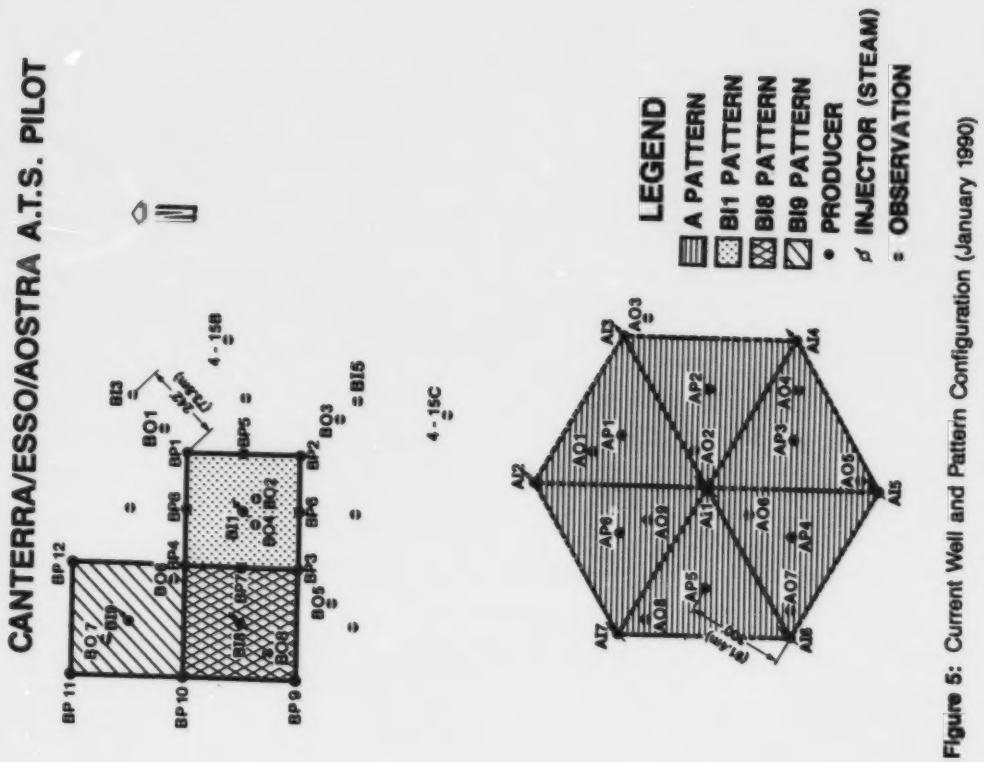

Figure 5: Current Well and Pattern Configuration (January 1990)

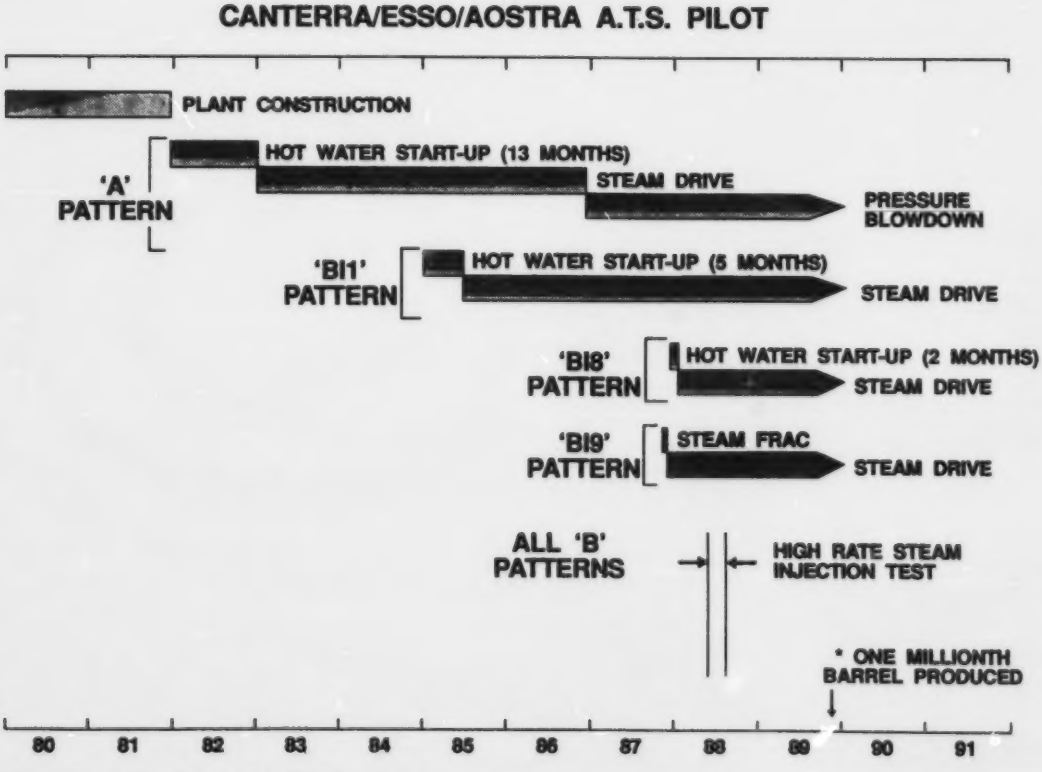

Figure 6: A.T.S. (Kearl Lake) Pilot Milestones

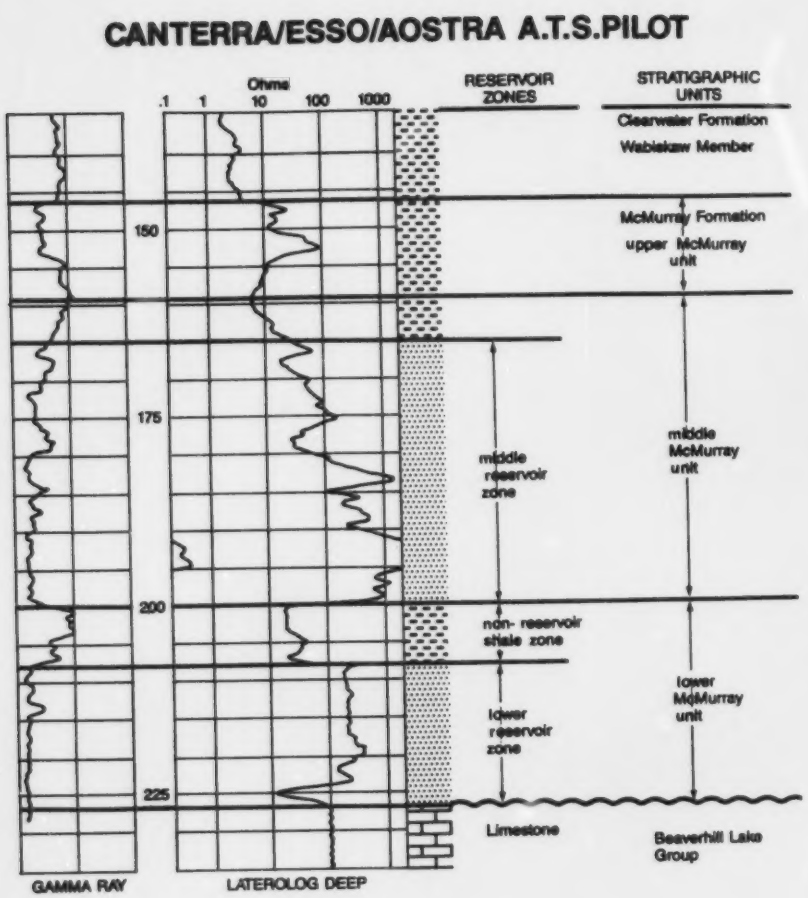

Figure 7. McMurray Formation Type Well BO4

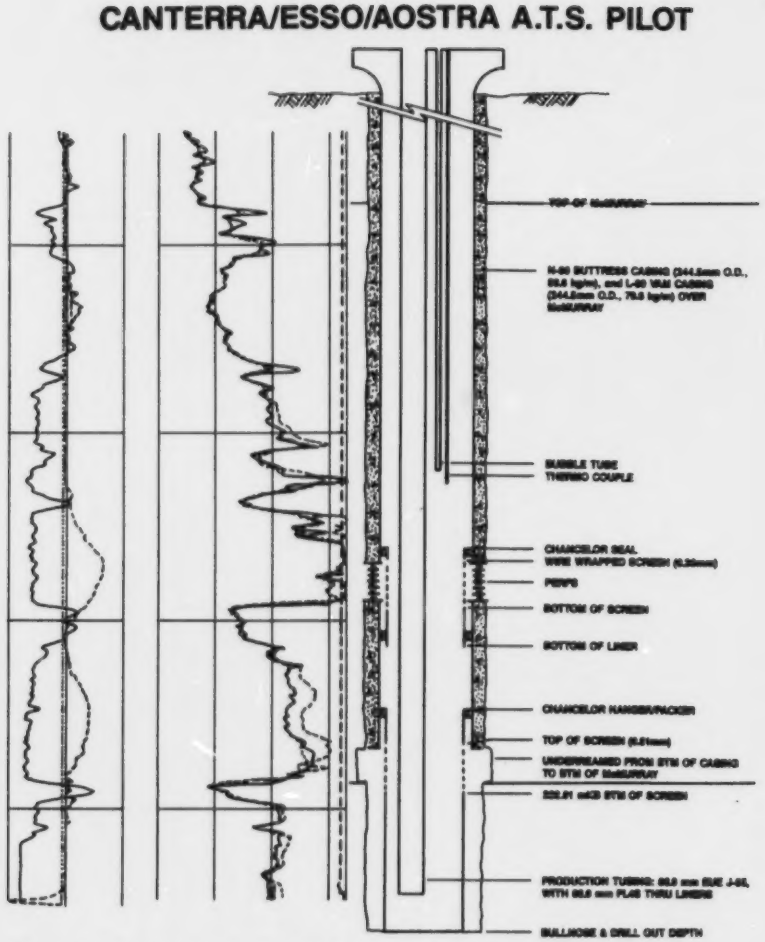

Figure 8: Typical Production Well Completion (BP7) — Open Hole In Lower McMurray

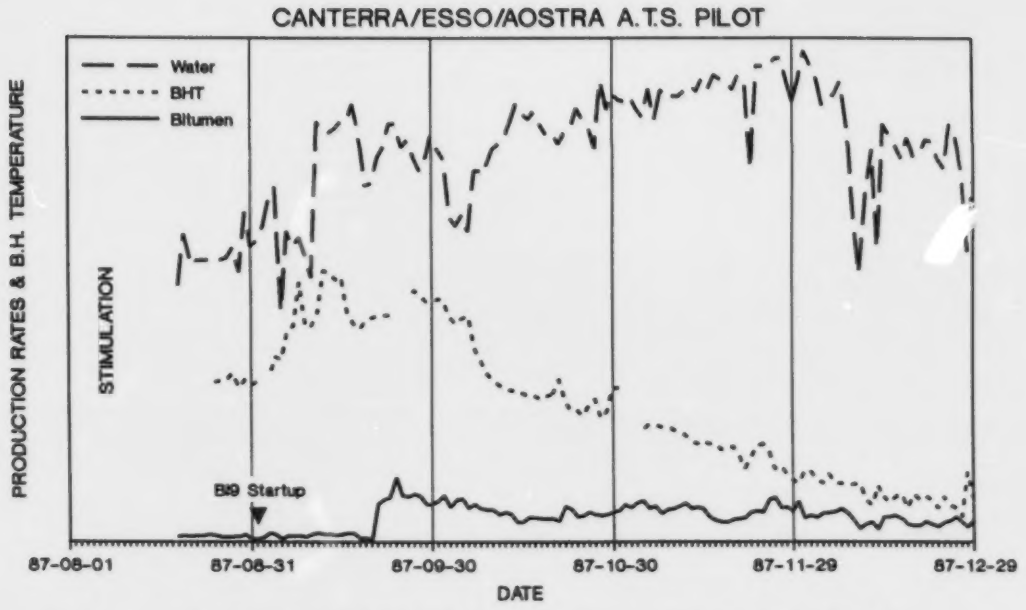

Figure 9. Production rates & bottom hole temperatures after the first stimulation of well BP10. The arrow indicates the date injection well BI9 was started up.

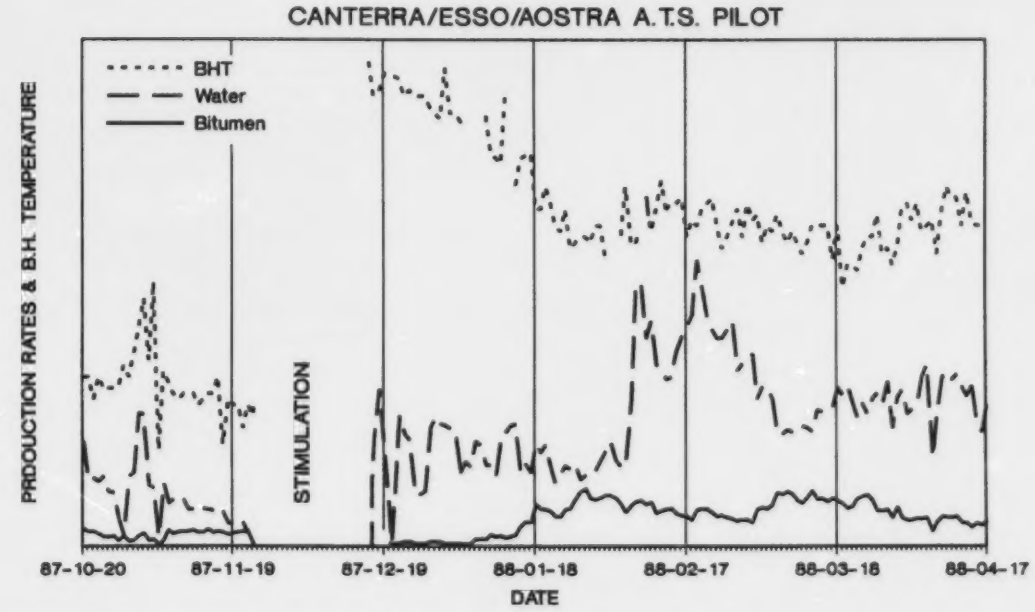

Figure 10. Production rates & bottom hole temperatures before and after the fifth stimulation of well BP4.

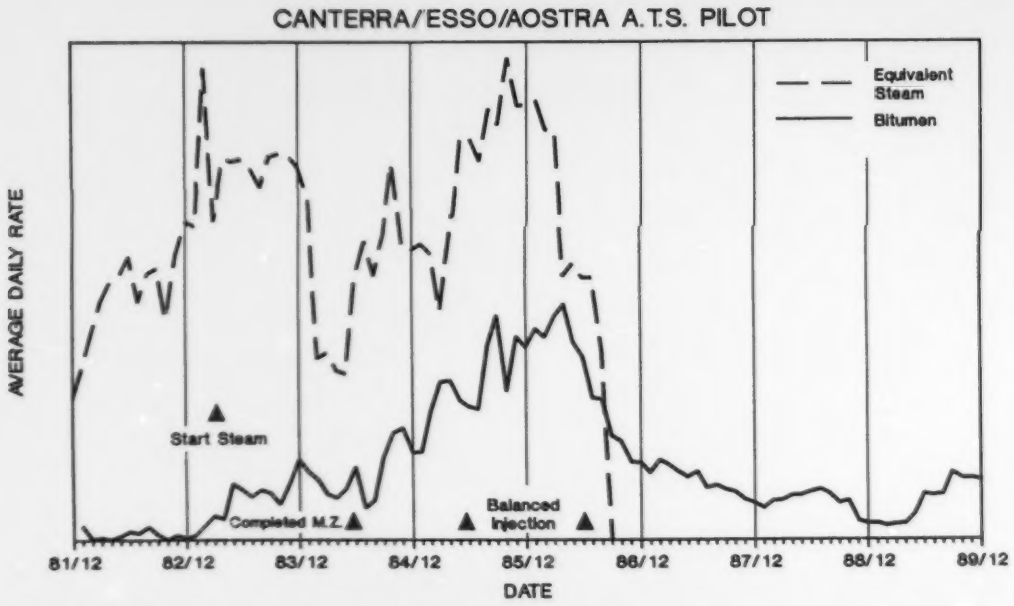

Figure 11. 'A' pattern rate performance.
The arrows on the plot indicate when the injection was switched to steam from hot water, when the middle zones were completed, and when the balanced injection test was conducted.

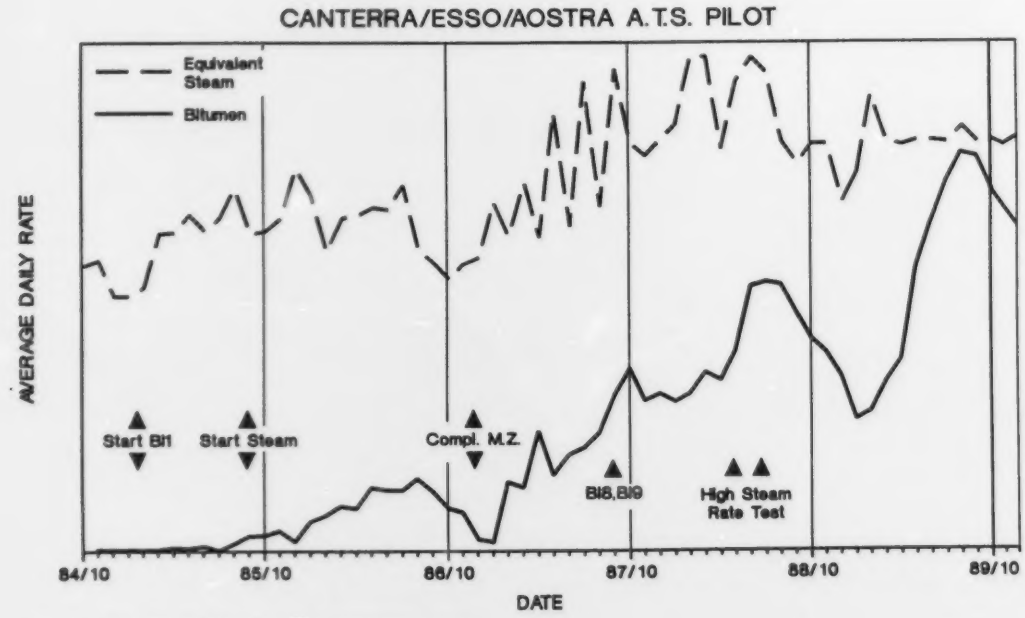

Figure 12. 'B' patterns rate performance.
Arrows on the plot indicate when the injection well BI1 was started up, when BI1 injection was switched from hot water to steam, when the middle zones were completed, when injection wells BI8 & BI9 were started up, and when the high steam injection rate test was conducted.

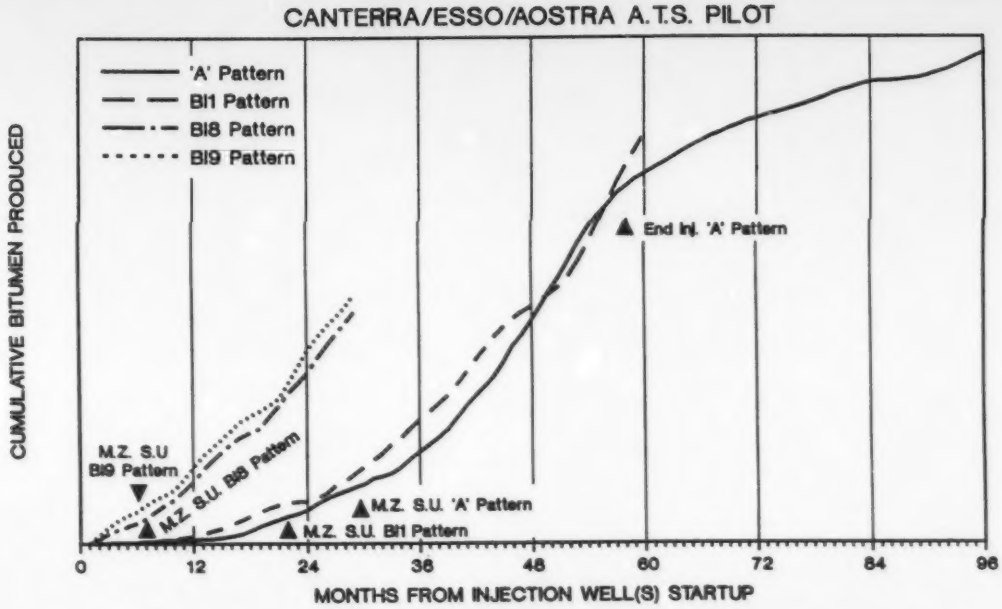

Figure 13. Comparison of cumulative bitumen production per well for all patterns. Arrows indicate the month in which the middle zones were completed in each pattern, and the month 'A' pattern injection ended.

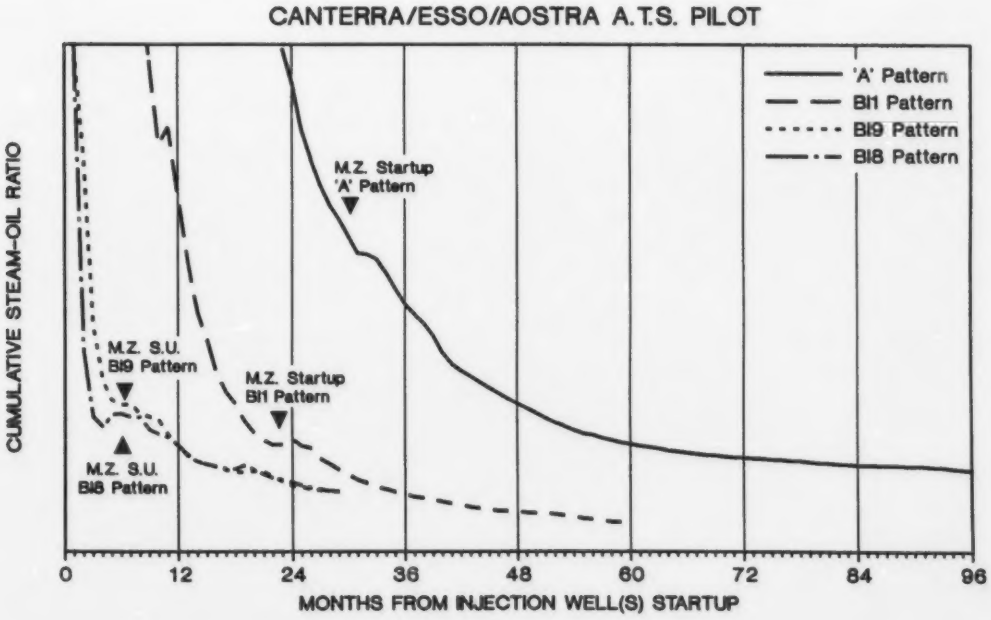

Figure 14. Comparison of patterns' sor performance.
Arrows indicate the middle startup date for the pattern represented by each curve.

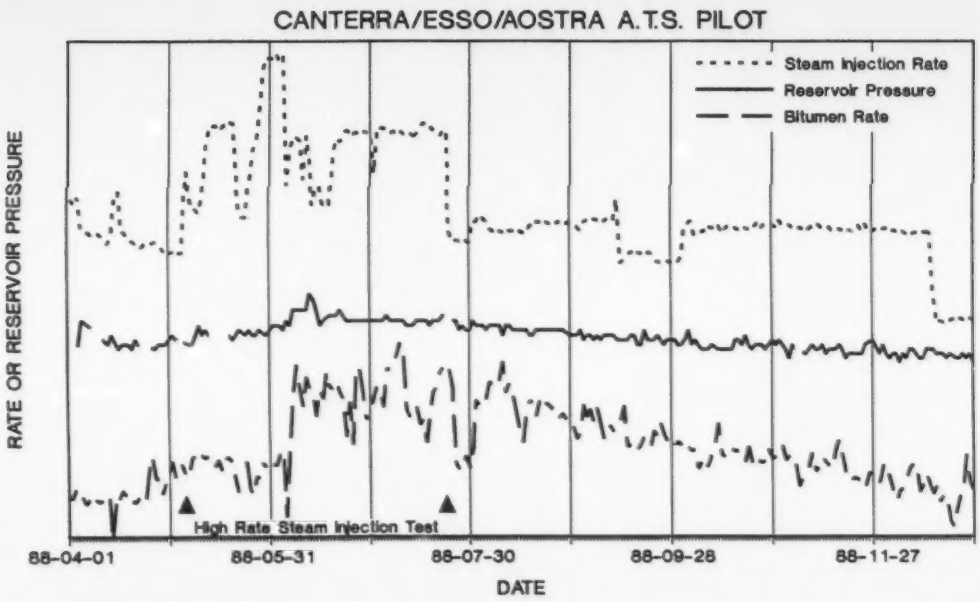

Figure 15. 'B' pattern high rate steam injection test.

Steam injection rates, bitumen production rates and reservoir pressures before, during and after the high injection rate period (as indicated by the arrows).

Bodo: Steaming Into The Nineties

D.W. Salahub, D.W. Mudie, Norcen Energy Resources Limited

Abstract. Norcen Energy Resources Limited has been operating a steam pilot project in the Main Bodo McLaren channel sand since 1985. This heavy oil reservoir is an unconsolidated sandstone with net pay thicknesses of up to 24 m. The pool covers approximately 520 ha and is underlain by bottom water along its western flank. The main objective of the pilot has been to compare the performance of the cyclic steam and steam drive processes to in-situ combustion, which was conducted at an adjacent pilot until 1986.

The Steam Pilot is a single pattern 8 ha 9-spot with an additional three observation wells. A combination of cased and open hole completions are employed, and all wells have been equipped with screens for sand control purposes. A one year primary production phase was followed by up to four cyclic stimulations at each of the nine project wells. Production has exceeded expectations as well as the performance of the Fireflood pilot. The project is currently in the final steamflood phase. Based on the performance to date full commercial scale development is envisioned for the pool sometime in the 1990's.

GEOLOGY AND RESERVOIR DESCRIPTION

The Main Bodo Steam Pilot is located some ten miles southeast of Provost, Alberta in Section 20, Township 37, Range 1, West of the Fourth Meridian (Figure 1). The Pilot is located in the Provost Upper Mannville "B" Pool, the most productive portion of which underlies portions of Sections 17, 18, 19, 20, 29 and 30, all in 37-1 W4M (Figure 2). Commonly called the "Main Bodo Pool", it is only part of a larger channel sand complex that stretches for some 26km east-southeast into Saskatchewan (Figure 3).

The Main Bodo Steam Pilot produces from the McLaren channel sand, which has net pays up to 24 meters, the highest pays being along the western edge of the pool. This channel sand was regionally deposited as part of the aforementioned extensive McLaren channel system. The system was cut in Waseca-McLaren time into previously deposited subtidal to shallow marine sequences and contemporaneously deposited overbank and interchannel deposits. As shown on Figure 3, the system enters Alberta as a single channel and branches into multiple channels in the northern part of Township 37. Here it becomes more estuarine in nature. The estuary development is a result of encroachment of a boreal sea from the north which caused bifurcation and raising of the base level of the Bodo channel several kilometers north of the Main Bodo Pool.

The McLaren sand as found in the Main Bodo Pool is composed of fine to medium grained, poorly to moderately well sorted subilitharenites with some very minor constituents including kaolinite and siderites. The sand is unconsolidated, generally exhibits good homogeneity, and displays excellent porosity and very high permeability. One exception to the homogeneity is the presence of a breccia sequence comprising sand with several discontinuous beds of clay and shaly silt clasts in the upper portions of the channel. Further discussion of the geology in the pilot area is contained in the references[1].

A summary of the pool reservoir and fluid characteristics appears in Table 1. The location of the Steam Pilot within the Main Bodo Pool and proximity to the Main Bodo Fireflood Pilot is shown in Figure 2. The Fireflood was operated by Norcen and it's Main Bodo working interest partners (Canadian Occidental Petroleum Ltd., Esso Resources Canada and Murphy Oil Company Ltd.) in Section 17-37-1 W4M from 1975 through until 1982. An expansion was operated by Norcen through early 1986, at which time air injection was permanently suspended. The Fireflood acreage is currently being operated in a primary production mode. A more complete description of the primary production and Fireflood performance is contained in the references[2].

PILOT OBJECTIVES

Although the Fireflood pilot had shown encouraging results in terms of incremental recovery, the operational problems inherent in a Fireflood, especially sanding, made a steam based process

appear more attractive. Despite the higher initial capital cost, Norcen was confident that the use of wire wrapped screens as sand retention devices could be successful in a thermal environment when the oil viscosity had been lowered. Screens had been tried in primary production applications with little or no success. Sand retention was possible, however, oil inflow was severely restricted to levels that did not allow economic operation of the applicable wells. This was attributed to the high pressure losses occurring across the screens due to the high viscosity of the oil.

Along with the prospects for improved economics based on similar projects in North America, Norcen anticipated higher ultimate recoveries using a combination cyclic steam-steam drive process than with the fireflood process. Recovery estimates of up to 45 percent of the pilot area oil in place were believed attainable compared to 30 percent at the adjacent Fireflood and 10 percent from primary production alone. A proposal for assistance in funding a portion of the Steam Pilot project was approved by the Alberta Oil Sands Technology and Research Authority in 1984 and they became a project participant shortly thereafter.

The main objectives in conducting the Main Bodo Steam Pilot are as follows:

a. To compare the performance of a combination cyclic steam-steam drive project to that of a wet combustion Fireflood in the Main Bodo reservoir.
b. To establish reservoir performance data from steam stimulation-steam drive for the Main Bodo pool to determine the ultimate commerciality of the process. Such information as oil-steam ratios, production rates, injectivity, operating temperatures and pressures, ultimate recovery and fluid property data would be gathered.
c. To confirm that sand control could be achieved through the use of wire wrapped screens (or alternate technology) in a thermal environment.
d. To optimize the future operations of a commercial scheme by way of experimentation at the Pilot. Process variables such as cyclic steam slug size, cycle length, completion techniques and spacing would be examined.

The project was designed to be operated in four stages. The first stage was to place the wells on primary production, next begin multicyclic steam stimulation, followed by a steam drive and finally a heat scavenging waterflood. The project was estimated to last approximately 10 years. The time frame for these four phases is shown below:

Mar/85 – Feb/86	Primary Production
Apr/86 – Jun/89	Cyclic Steam Stimulation
Jul/89 – Dec/92	Steam Drive
Jan/93 – Dec/94	Heat Scavenging Waterflood

PROJECT DESCRIPTION AND WELL EQUIPMENT

The Main Bodo Steam Pilot consists of one single 8 hectare (20 acre) inverted 9-spot pattern (Figure 4). The interwell distances are therefore 141 m from corner to side wells and 200 m from the central well to each of the four corner wells. The corner wells are G23, I25, K23 and I21 whereas the side wells are H22, H24, J24 and J22. The central well, which is used as the injector during the steamflood phase of the pilot, is I23.

The pilot employs three observation wells, OB1, OB2 and OB3. The locations of these wells are also shown on Figure 4. In all three cases these wells are located about 25m from the nearest pilot producing well. The water source wells are located east of the Pilot (PW4) and within the confines of the Pilot (PW3). Flowlines to these Ribstone aquifer wells provide the required feed water for steaming operations. A dedicated Nisku salt water disposal (SWD) well is located 1 km east of the Pilot and is connected by pipeline.

The Steam Pilot production/injection wells were drilled and completed in early 1985. Conventional open hole logs including the DISFL and CNL-LDT-GR were run on all wells. RFT's were run to determine the reservoir pressure in the Pilot area. CST's were run following the casing of Pilot wells to better define the pay zone location for the open hole well completions.

The casing design for the Pilot wells was made with adequate consideration for all possible casing failure modes in a thermal environment. These include buckling, tensile failure and joint pullout. As evaluation of different casing designs did not form part of our objectives for the Pilot, Norcen opted for 177.8 mm MN-80 BT&C with oversized collars. The use of less-costly casing designs in a commercial scale future project will likely be considered. All production strings in the Pilot wells were cemented to surface using a standard thermal blend; Class "G" + 40% silica and 0.5% CFL. The casing over the zone of interest was sand blasted prior to installation in the hopes of improving the cement to pipe bond in this critical region. Our cementing success was acceptable; however, poor bonds on some Pilot wells necessitated the purchase and use of one string of insulated tubing for cyclic steaming on several Pilot wells. This string was subsequently run into the central injector I23 for the steamflood phase of the Pilot.

Norcen has experimented with completion design by utilizing both cased and open hole completions. The Pilot corner wells and central well I23 were all cased through the pay zone and subsequently perforated conventionally at 13 SPM, generally in the middle-bottom portion of the zone. The side wells were completed open hole. The side wells were equipped during the primary production

phase with sand screens sized using the standard theory. Upon commencement of the cyclic phase, all wells were equipped with sand screens.

The Pilot wells have a mix of 73 mm and 89 mm tubing strings, which has allowed the use of both 2 and 2 1/2 inch insert pumps. Pilot pumping performance has been studied at length and is discussed in the literature[3].

Norcen originally installed HEP HV-100 hydraulic units at all pilot wells. Due to capacity limitations and operational problems of an ongoing nature, conventional C-456 pumpjacks have been installed at three pilot wells.

PROJECT FACILITIES

A brief schematic of the Main Bodo Steam Pilot process flow diagram appears in Figure 5. A plot plan of the facilities layout appears on Figure 6. The design basis for the process flow equipment utilized at the pilot is summarized in Table 2.

As shown in Figure 6, the Steam Pilot facilities are located centrally and to the south and east of the 123 (central injector) well. This arrangement ensures the most efficient use of the available utilidor space and minimizes the total length of steam injection lines required for cyclic steaming of all 9 pilot production/injection wells.

Each of the nine project wells are tied into the plant by two surface lines. The production/steam injection lines are manifolded into each of the group, test and steam injection systems. One surface line is used for all of these functions. The annulus gas line is manifolded into the annulus gas system, a bypass, the fuel gas blowdown and the utility steam blowdown systems. This allows the production steam injection lines to be blown down and purged during shut-in's, eliminating the need for heat tracing of these lines.

The annulus gas from each well goes through the aforementioned annulus gas flowline with individual well back pressure control. The gas is then directed to a separator and metered for subsequent use in a vent gas recovery system (steam generator fuel supply) or alternately bypassed to the vent gas knock out drum and flared to atmosphere.

Normal emulsion flow, with the exception of test well flow, travels through inlet heat exchangers prior to gas separation. The heat exchangers allow heating or cooling of the inlet emulsion to the specified inlet emulsion temperature. The test train tankage operates in a batch basis: ie. the test volume is stored in the test train gauging tank after gas separation in the associated test gas inlet separator. The test tanks are then pumped out prior to commencement of the next test. Two separate test trains allow for frequent testing of the 9 pilot producing wells.

After gas separation, the group emulsion flows to the free water knock out vessel (FWKO). Separation of oil and water phases in this vessel is aided by long residence times and internal flow baffles. Any unbroken emulsions are transferred to the surge tank where they are subsequently pumped through the Colt treater for final dehydration. Sales and recycle oil tanks are located onsite with the ability to truck off sales oil or pump across to the 1-19-37-1 W4M pipeline terminal.

Desand capability at the Steam Pilot is provided using cone bottom tanks and desand jets in vessels where sand production accumulates. This includes the group FWKO and both test train gauging tanks. Batch movement of the fluidized bottoms in these tanks is employed in moving the sand slurry to a desand tank where cyclones are used to provide final separation of the sand from the slurry.

Water production off of the FWKO flows to a skim tank for residual oil removal and then onto storage tanks prior to injection down the pilot SWD well, 8C-20-37-1 W4M.

Steam generator water provided from project water source wells is filtered using cartridge filters and pumped through a raw water storage tank. A series of ion exchange softeners are used to treat the water to the required inlet specification for the steam generator.

The steam generator is a 25 MMBtu unit capable of producing 270 m^3/d of 80% quality steam.

The majority of the plant heating/cooling requirements are provided for by a pressurized glycol system utilizing a 60/40 diethylene glycol mix and a glycol heater rated to 1,800 KW. Instrument/utility air is provided for by a set of air cooled rotary screw air compressors. Fuel gas for the Pilot operations is provided by pipeline from Nova and the plant supply is regulated at 690 kPa.

PRIMARY PRODUCTION

Primary production from the Main Bodo Steam Pilot began in March, 1985 when well 121 was completed. By August, 1985 all nine project wells were on primary production. This phase continued until March, 1986 when cyclic steam injection was initiated at well 123. By September, 1986, all nine pattern wells had received one cyclic steam stimulation.

For primary production purposes, the wells were equipped in two different ways. The open hole wells, along with control well 123 were equipped with sand screens while the corner cased hole wells were produced without screens. The wells without sand screens performed very well with oil rates of up to 10 m^3 oil/day over the one year primary production period, while only being produced at approximately 50 percent drawdown. The inability to pump the wells off was due to a combination of poor pump efficiency due to sand and gas problems as well as

the high viscosity oil which limited rod fall. This is typical for the Main Bodo pool and was not unexpected.

The wells equipped with sand screens demonstrated very low production levels, of less than 3 m^3 oil/day over the same one year production period. This was expected based on prior sand screen tests in other areas of the pool. Downtime was less in the sand screen wells due to the retention of sand. In contrast to the conventionally completed wells, these wells were essentially pumped off. The high skin factor (pressure loss) due to the sand screen was apparent. To confirm this phenomenon, the sand screen installed at the central 123 well was pulled following six months of operation. Total fluid productivity increased by a factor of seven, with the fluid level increasing from a pumped off condition to a 50 percent draw-down. It was thus concluded that the use of sand screens in a primary production mode posed severe restrictions on well productivity.

Data gathering during the primary production phase consisted of measuring pressures at the three observation wells and four production wells using bubble tubes. IPR and pressure build-up tests were conducted on several wells. The unsteady state behavior, changing pump efficiencies due to sand and gas problems and the high viscosity oil all prevented any useful quantitative data from being attained.

Total primary recovery during the one year production phase was about 3 percent of the well spacing oil in place. Simulation estimated the ultimate primary recovery would have been 8–10 percent had the wells been produced to their economic limit.

CYCLIC STEAM STIMULATION PHASE

Cyclic steaming began in March, 1986 at the central 123 well. Prior to steaming, all wells were equipped with sand screens to control sand production. Insulated tubing with a gas blanket was also used in wells which had questionable cement bond characteristics to ensure casing integrity. No casing failures were noted in the four cycles conducted.

Production Performance

The first cycle steam slug sizes at the Pilot wells were planned to be 4,000 m^3 cold water equivalent (CWE). This volume was selected based on reservoir characteristics, prior cyclic tests conducted on other wells in the pool, and other similar projects. A maximum bottomhole pressure constraint of 14,000 kPa was set to prevent injection above fracture pressure although this limit was in fact never reached. Injection rates throughout the cyclic phase were generally restricted by the generator output of 270 m^3 CWE per day although surface constraints such as source water limitations did come into play in certain instances. Actual Cycle 1 injection volumes were very close to those anticipated.

The first cycle production response was very encouraging with peak oil rates per well of over 60 m^3/day observed. The average first cycle response of the 9 pilot wells saw calendar day oil rates significantly higher than the 10.7 m^3/day estimated originally. The first cycle response exceeded expectations with the wells demonstrating high fluid productivity of up to twice that anticipated despite the installation of the sand screens. It was not uncommon to have wells producing at the equipment maximum of 60 m^3/day total fluid at only 50 percent drawdown.

The second steam injection cycle was initiated in late 1986. The steam slug given to Pilot wells was essentially the same as Cycle 1. Injection pressures dropped on average 3,000 kPa due to the high depletion seen in Cycle 1. In general, the productivity of the wells in Cycle 2 was lower with higher water cuts also being evident. Oil response after steaming was also delayed by 2–4 weeks longer than during Cycle 1. During the 10 month second cycle the Pilot wells averaged about 30 percent less oil production per calendar day then during Cycle 1 with overall oil steam ratios declining 20 percent.

Because of the declining oil rate observed, the decision was made to increase steam injection volumes in the latter portions of Cycle 2 and all of Cycles 3 and 4. First, a desired incremental heated zone was assigned to each well prior to steaming. Then an energy balance was conducted to calculate the steam required to reheat the previously heated zone as well as the new incremental volume. Based on the incremental volumes assigned steam slug sizes were increased up to 80 percent by Cycle 4. Two wells were not resteamed for Cycle 4 due to their poor performance in Cycle 3. Average calendar day oil rates declined 15 percent in Cycle 3 and a further 7 percent in Cycle 4. A production profile of a typical well is shown in Figure 7.

Overall, the cyclic production performance was excellent with an average incremental recovery of 17 percent of the oil in place being observed over the 3 year cyclic phase. The average calendar day oil rates were slightly less than the 11.9 m^3/day originally forecast with oil steam ratios higher than the 0.55 forecast.

Data Gathering/Analysis

With most of the Pilot wells equipped with downhole bubble tubes, significant effort has been expended towards data gathering and analysis. Pressure falloff tests were conducted following most injection phases. In general, these tests were only

useful in a qualitative manner due to the assumptions made. Negative skins and steam permeabilities of approximately one tenth absolute permeability were commonly seen. Build up tests were also conducted occasionally. These tests gave results similar to the fall off tests although some tests revealed high skin factors which prompted remedial action including removing and servicing sand screens. Temperature data was also collected at the three observation wells during the cyclic phase.

The bottomhole pressures were also used in supporting simulation work which was helpful in determining pilot strategy. Sensitivities on such items on steam slug sizes,resteaming time, completion interval,and future performance predictions were tested in a 2D radial model developed using CMG's ISCOM thermal simulator.

Oil, water and gas analyses were also routinely performed on the Pilot wells. The oil analyses showed that on almost every cycle, early oil production was more viscous and had a higher density than the insitu oil. This is likely due to steam stripping of the lighter ends from the near wellbore crude. Water analyses based on chlorides monitoring were used on a routine basis to perform cycle injection/production water balances. As well the chloride analyses were used to validate interwell communication, although it was not present to any large degree. The gas analyses taken indicated high levels of CO_2 production (up to 20 percent) was being seen in the early stages of cycle production. This phenomenon has been discussed in several papers and is believed to be due to carbonate mineral dissolution.

Equipment

The most critical and uncertain item in the performance of the Pilot with respect to the ultimate well performance was the success of the sand control devices employed. In the Fireflood Pilot to the south, and in primary wells surrounding the Steam Pilot, sand production was and continues to be a major problem. The sand screens have performed very well at the Steam Pilot in a high temperature mode, by restricting sand inflow yet allowing high productivity. Rates of up to 100 m^3 per day total fluid have been observed compared to peak fluid rates of only 8 m^3 per day in a primary production situation. Several instances of screens washing out with perforating sized holes were observed. One solution was to pull the screen, patch the holes and rerun the screen. In more severe cases, additional perforations, sand jetting slots in the casing or running a blast joint were used to solve the problem.

Plugging of the screens has also been observed in several instances. Several screens have been found to be plugged with a calcium carbonate scale which was related to the high concentrations of CO_2 being produced. The screens were successfully cleaned with HCl and rerun. Plugging was also apparently removed in several cases by injecting a one day slug of steam. Production without a screen was attempted on pilot wells several times. While productivity was found to be 20–25 percent higher, the wells would not pump continuously and sanded in frequently.

Pumping performance has not been ideal at the Pilot. High GORs have caused significant efficiency problems with the insert pumps employed. Lowering the pump has helped some of these problems but in certain wells this is not possible and efficiencies continue to be poor. Steam flashing early in the cycle life also has caused low efficiencies. The only solution found to this problem was to wait for the well to cool off prior to producing it. Finally, the surface pumping equipment at the Pilot was designed for a 50 m^3/day total fluid rate. In reality,based on observed bottomhole pressures, the inflow performance exceeded 100–150 m^3/day total fluid at certain wells. As outlined earlier, upsized pumping equipment has been installed at capable wells later in the cyclic phase.

The Pilot treating and steam generation facilities have performed very well. No major problems have been encountered although several modifications have been made. To make use of the larger than anticipated solution gas volumes produced, a vent gas recovery system was installed and designed to partially feed the steam generator needs. Later in the cycle when pressures and rates declined, previously recovered annulus gas would be vented to avoid back pressuring the well and decreasing inflow. The Colt treater has performed very well; off-spec oil has not been a problem.

CURRENT ASSESSMENT AND FUTURE PLANS

One of the primary objectives behind the Steam Pilot was to compare and assess the technical and economic merits of it relative to the original 8 hectare Fireflood project conducted one mile south. While the capital and operating segment of this comparison is not available for discussion, it is clear from Figure 8 that the Steam Pilot has out performed the Fireflood Pilot in terms of production. As well, the Fireflood expansion did not perform as well as the original 9 spot pattern, which leads to the conclusion that a steam based process has the most EOR promise in Main Bodo.

The next and current phase of the Bodo Steam Pilot is to follow-up the 4 cycle steam stimulation phase with a steam drive by way of continuous injection into the central 123 well. Norcen considers this phase to be very important in achieving the high recoveries forecast for the Pilot and future projects.

Depletion indices during the four cycles conducted were well over unity which has resulted in serious pressure depletion in the Pilot region. On a commercial scale, a cyclic project alone would be faced with lower oil steam ratios and calendar day oil rates than observed in the Pilot.

The steam drive phase of the project was initiated in July 1989. Early response to the drive was masked by residual Cycle 4 effects on the producers. At the present time, more definitive response has been observed by way of significantly reduced GORs and increased fluid productivity at most pilot wells. Performance thus far has been encouraging with production being equal to or better than forecast and slightly higher than at the end of the cyclic phase.

The next 2–3 years of steam drive performance will be very important in determining the ultimate recovery process and pattern size to be chosen for the pool. A follow up residual heat scavenging waterflood is planned following the steamflood phase. By the time these phases are complete, prototype development would be our next objective. Norcen envisions adding 1–4 patterns surrounding the current project as the next Pilot phase required. Total commercial development of the pool could follow in the mid-late 1990's depending on oil prices, royalty regimes and performance of the current pilot.The full scale project envisioned would last approximately 20 years with average production of 400 m^3/day. Cumulative recovery assuming a 45 percent recovery of the development area within the better portion of the pool would be 3.3 10^6 m^3.

CONCLUSIONS

1. Sand screens employed in the primary production phase at the Main Bodo Steam Pilot posed severe restrictions on well productivity due to the high viscosity of the crude. In the thermal phase of the Pilot the screens did not impose any significant production restriction, and were successful in preventing sand from entering the wellbore.
2. Cyclic production performance was very encouraging with fluid rates of over 100 m^3/day being observed. Because of the better than anticipated performance, several pumping units were replaced with larger equipment. Overall, during the three year cyclic phase an average incremental recovery of 17 percent was seen.
3. The significant effort associated with data gathering at the Pilot provided Norcen with additional information that assisted in our understanding of the cyclic steam process in the Main Bodo pool. Data collected included build-up and fall-off tests, continuous downhole pressure and temperature monitoring at pilot wells and frequent fluid analyses.
4. No major facility problems have been seen to date. The Coit treater has performed well with no off-spec oil observed. Higher than anticipated gas production during the cyclic phase has been conserved and is now used to fuel the steam generator.
5. Through the cyclic phase, the Steam Pilot has out-performed its Fireflood neighbor to the south. The Pilot is currently in the steam drive portion of the project which is an important part of the overall steam recovery process. This process is expected to ultimately achieve recoveries of 45 percent. Commercial development of the Main Bodo pool awaits completion of this portion of the pilot and, of course, will require favourable economic indicators in order to proceed.

Acknowledgments

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TABLE 1
PROVOST UPPER MANNVILLE B POOL
AVERAGE RESERVOIR AND FLUID CHARACTERISTICS

Depth (m)	720
Average net pay (m)	13
Gas-oil interface (m SS)	–27
Oil-water contacts (m SS)	–52
Formation air permeability (Darcies)	1–3
Average effective porosity (percent)	30
Initial oil saturation (percent)	80
Oil density (kg/m^3)	979
Oil formation volume factor (m^3/m^3)	1.03
Solution gas oil ratio (m^3/m^3)	11
Live oil viscosity (mpa·s)	2300
Dead oil viscosity (mpa·s)	5000
Bubble point pressure (kPa)	5340
Formation temperature (°C)	27
Original formation pressure (kPa)	5450
Water total solids (g/m^3)	25700
Water (pH)	8.2

TABLE 2
STEAM PILOT DESIGN PARAMETERS

CLIMACTIC CONDITIONS

Elevation	700 meters
Frost penetration	2.4 meters
Temperature range	–40 to +35°C
Relative humidity	10% to 100%
Wind — prevailing	NW
— maximum speed	80.5 km/h
— maximum gust	112.7 km/h

PROCESS CONDITIONS

	Design	Operating
Steam injection rate	252 m^3/d @ 13,445 kPa	252 m^3/d @ 8270 kPa (cyclic) @ 4500 kPa (drive)
Steam quality	80%	80%
Oil production	98 m^3/d (total)	58 m^3/d
	12.3 m^3/d (per well)	7.3 m^3/d
Water production	267 m^3/d (total)	–
	33.4 m^3/d (per well)	–
Sand production	1–2%	1–2%
Production temperature	5°C–200°C	100°C
Pressure at wellhead	–	–

FIGURE 1: BODO STEAM PILOT RESERVOIR LOCATION MAP

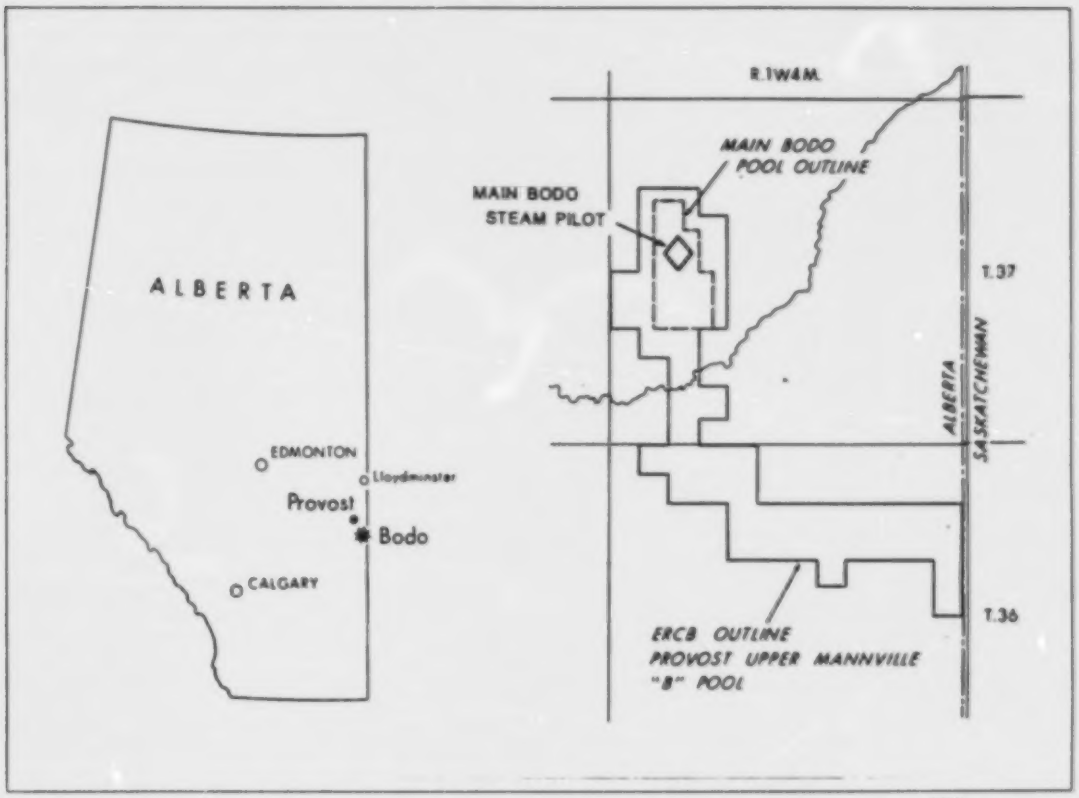


FIGURE 2: BODO STEAM PILOT LOCATION

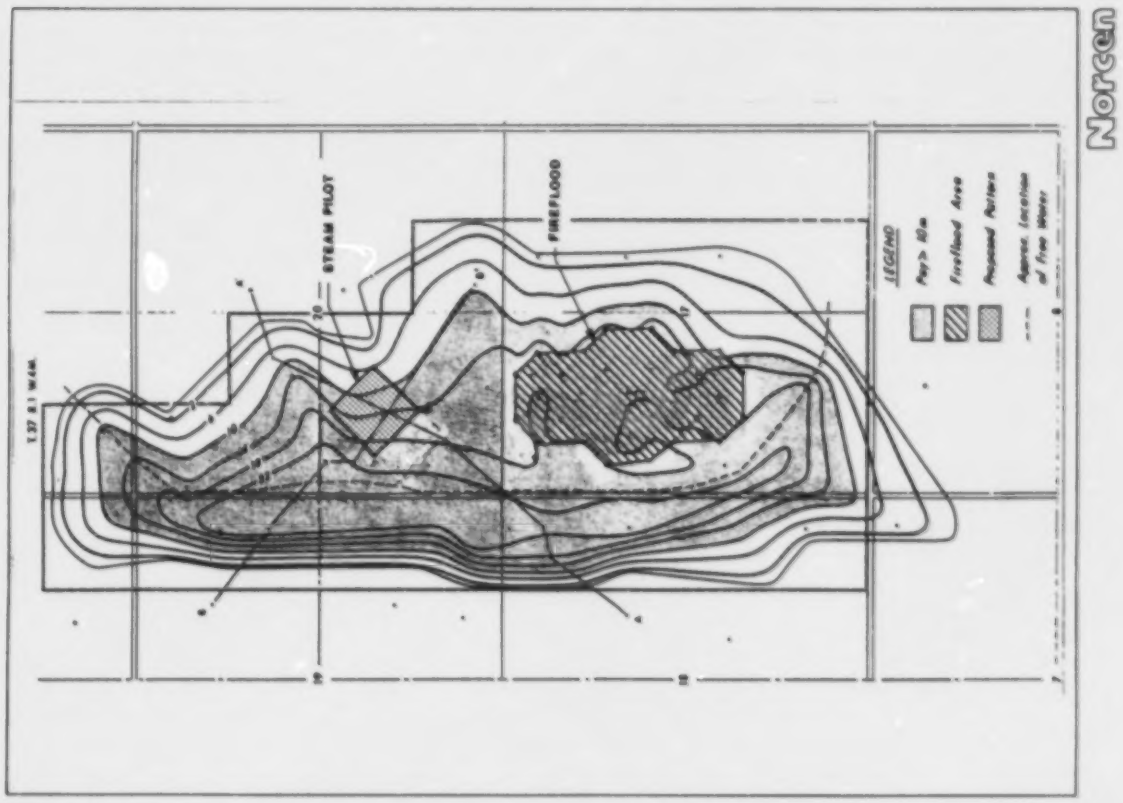
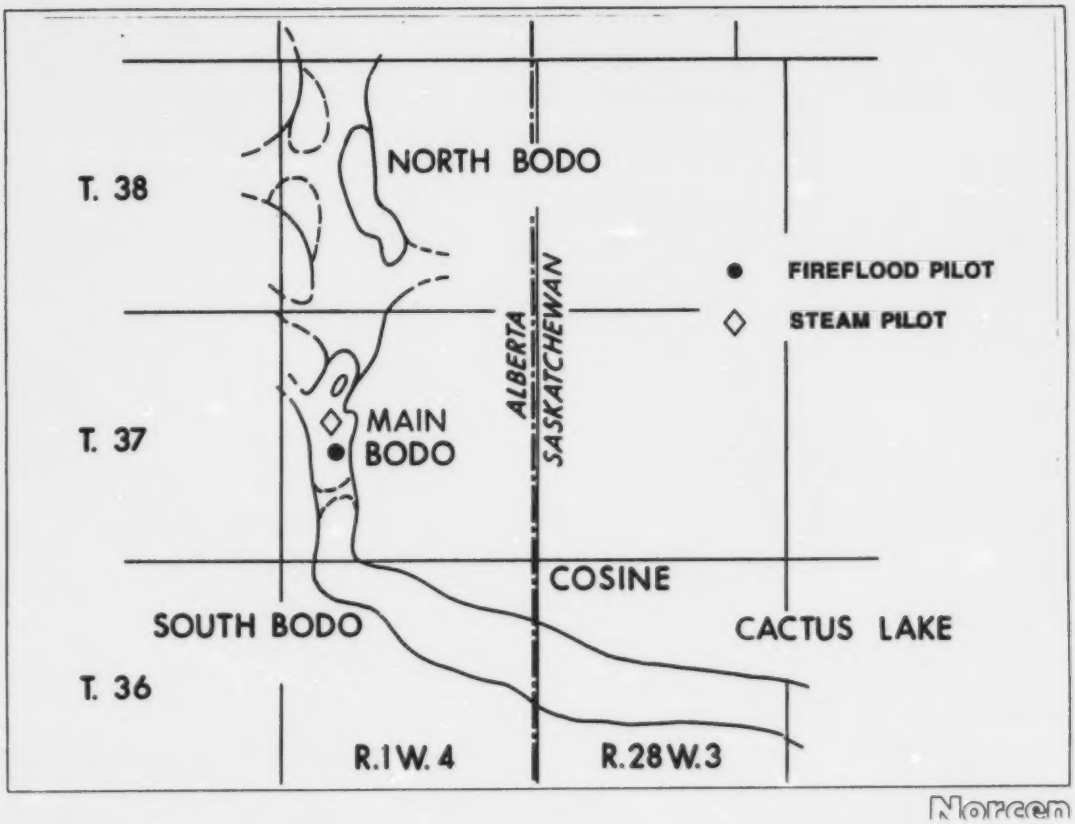


FIGURE 3: McLAREN CHANNEL SAND COMPLEX



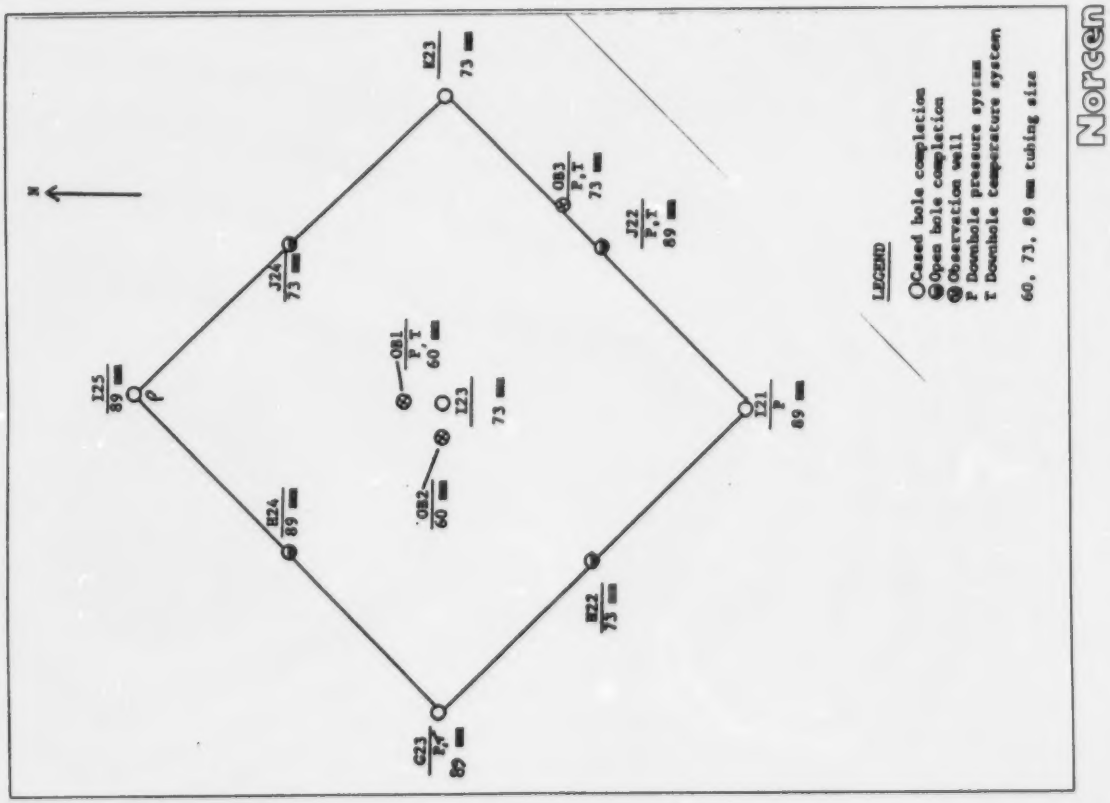


FIGURE 4: MAIN BODO STEAM PILOT PLOT PLAN

FIGURE 5: STEAM PILOT FLOW DIAGRAM

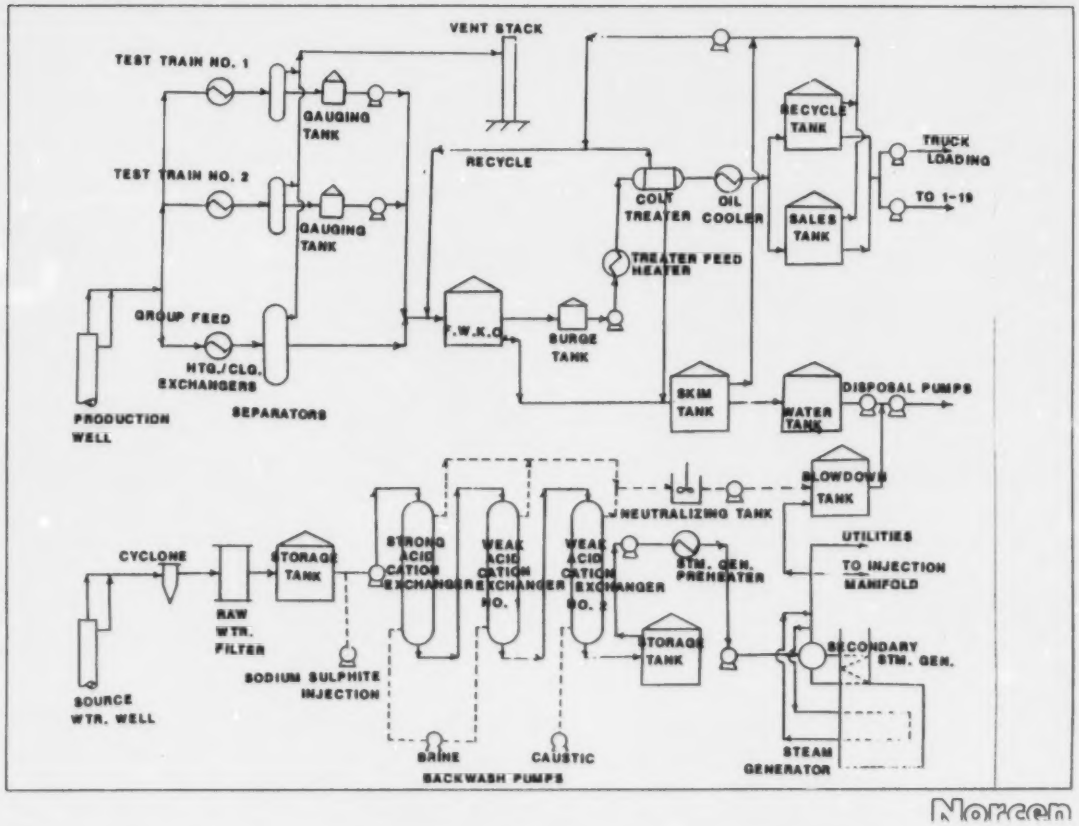
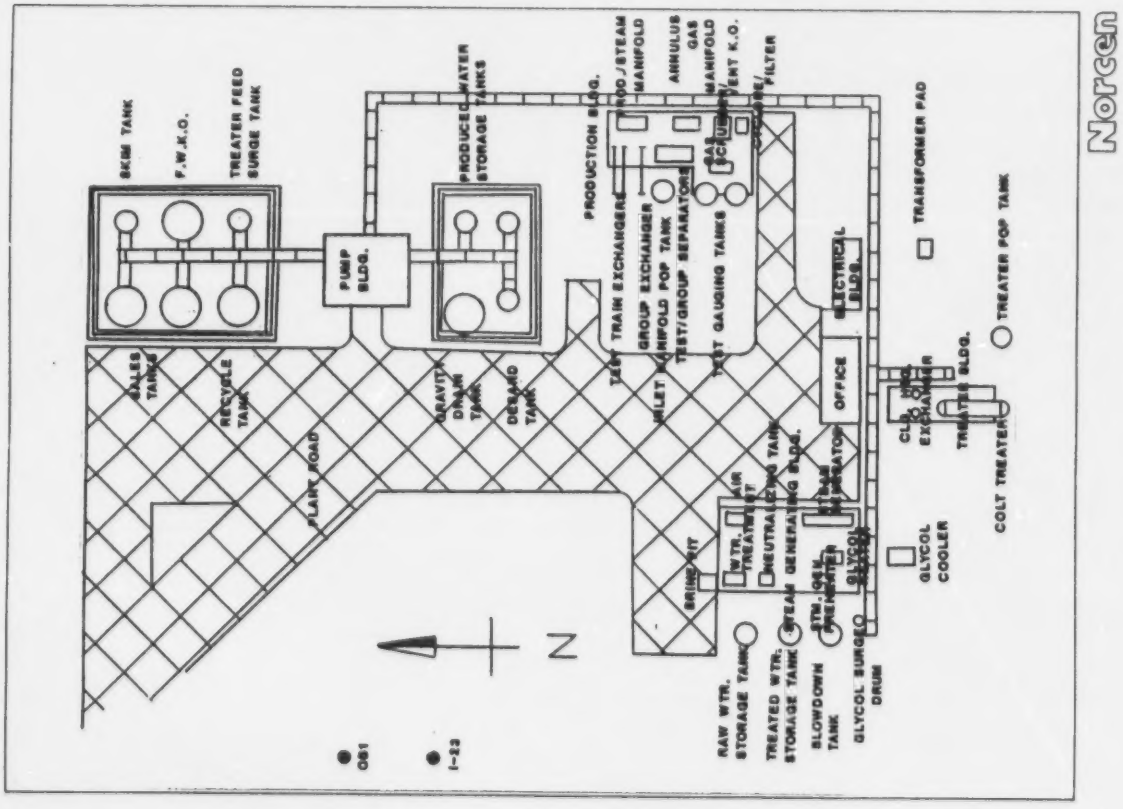


FIGURE 6: MAIN BODO STEAM PILOT FACILITIES PLOT PLAN



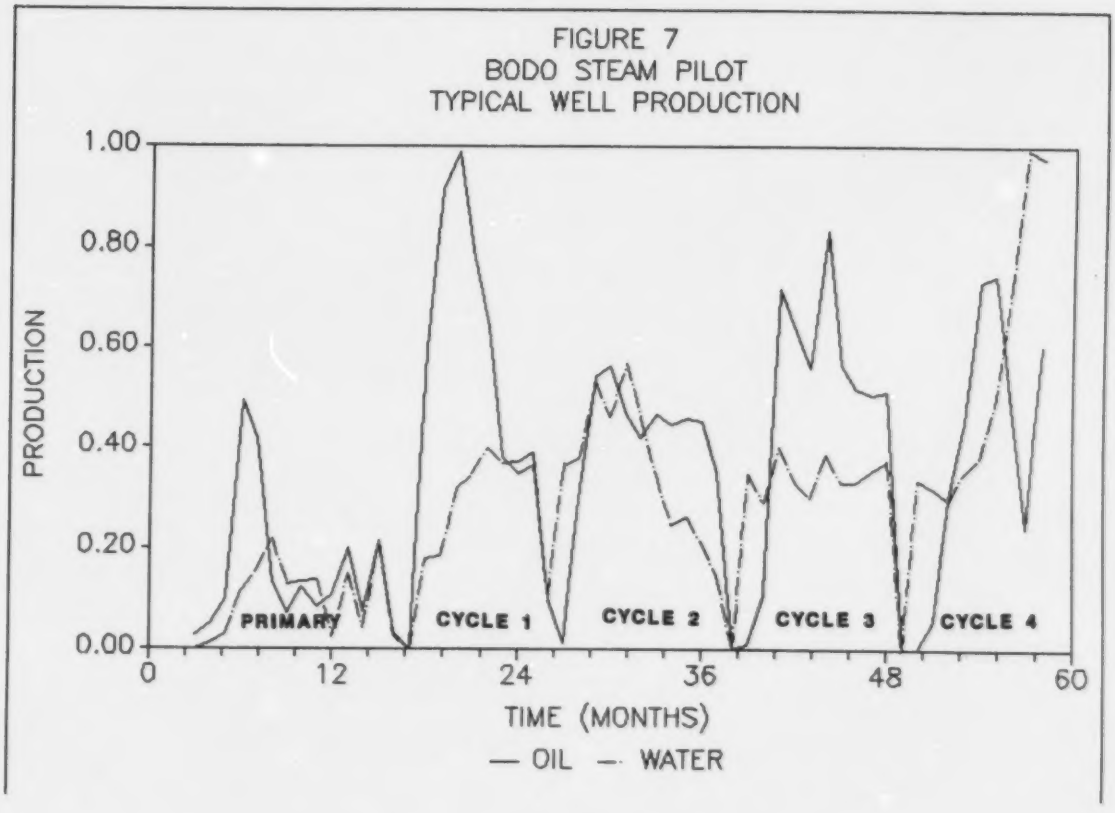
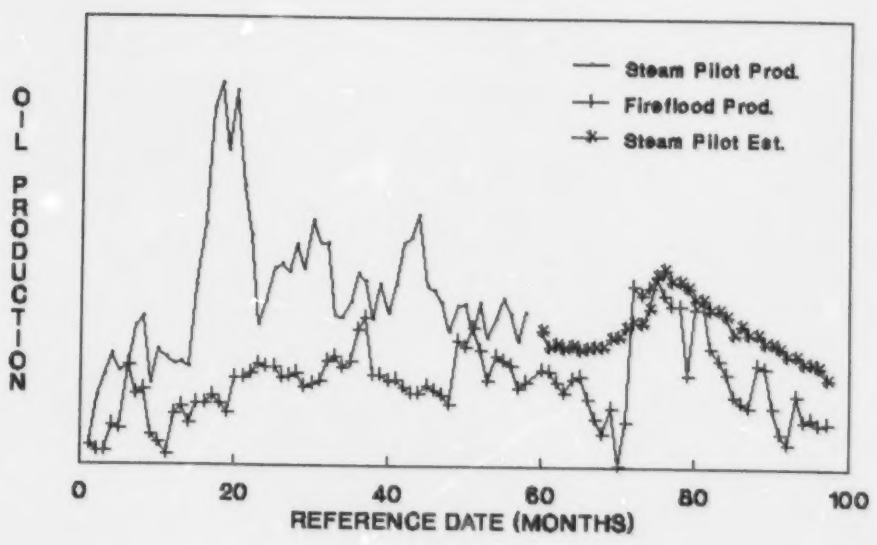


FIGURE 8
BODO FIREFLOOD VERSUS BODO STEAM PILOT
OIL PRODUCTION



Progress At Shell's Peace River In-Situ Recovery Operation

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Abstract. Shell Canada Ltd. has completed 10 years of operation of the Peace River In-Situ Pilot (PRISP) and three years of operation of the Peace River Expansion Project (PREP). Production performance at both projects continues to meet expectations.

Although future expansion plans are currently on hold, efforts continue to improve the efficiency of existing operations, to reduce operating costs and to develop methods to meet more stringent environmental guidelines.

This paper overviews Shell's experience in Peace River and plans for the future.

Introduction:

The Shell Peace River Oil Sands Project is located in northern Alberta, 400 km northwest of Edmonton (Figure 1). The producing formation, the Bullhead sandstone, is approximately 550 meters below surface in this area and has an average pay thickness of 25 meters. At the base of the formation is a highly permeable, relatively thin (2 meters) mobile water zone (Figure 2). This so-called Basal Water Zone (BWZ) is specific to Peace River, and is not typically found in the Cold Lake / Wolf Lake areas. Its presence is important in that it assists in the injection and areal distribution of steam in the formation.

The estimated net exploitable bitumen reserves of Shell's Peace River acreage are 1.4 billion cubic meters, of which 55% are estimated to be recoverable. The bitumen in place is characterized by 8-10°CAPI gravity and a viscosity of 200,000 cP (@20°C), the latter of which is the highest of all commercial thermal projects in Alberta.

Shell Canada's active research involvement in the Peace River oil sand deposit began in the early 1960's. Field and laboratory experiments through to the mid 70's culminated in October 1979 with the start-up of the Peace River In-Situ Pilot (PRISP) as a joint venture between Shell Canada Resources Limited (operator), Alberta Oil Sands Technology and Research Authority (AOSTRA), Shell Explorer Limited (a wholly owned subsidiary of Shell Oil Co., USA) and Amoco Canada Petroleum Company Limited. The pilot was designed to test the pressure cycle steam drive recovery process. This consisted of alternating high rate steam injection with periods of minimum injection (ie. pressure-up and blowdown), using dedicated injection and production wells. Correspondingly, it also resulted in cyclic periods of low and high bitumen production. The plant was thus designed for a bitumen production rate of 550 m^3/d and steam injection capacity of 2750 m^3/d (water equivalent). The project is now nearing the end of its originally forecast 10 year life and has met all original expectations. Based on performance of the current (and last) scheduled blowdown cycle, one more pressure-up/blowdown cycle may be added, extending the life of the pilot a further 1.5 years. As shown in Figures 3 and 4, PRISP performance to date has closely tracked the original forecast for overall recovery and OSR, with the probability of surpassing both before project end.

A commercial expansion was added during 1984 and 1985 (Peace River Expansion Project, PREP), and started up in October 1986. Shell Canada Limited's sole partner in this project is Pecten Canada Limited. (formerly Shell Explorer). Consisting of 213 directionally drilled wells divided into eight pads (Figure 5), the expansion increased bitumen production capacity to 1600 m^3/cd (daily average). On the plant side it increased steam generation capacity by 6400 m^3/cd and total gross produced fluid capacity to 8000 m^3/cd.

Much of what was learned in the earlier years of PRISP operation was used in the development of PREP. As a result, PREP involved an initial 2-3 year period of multisoak operation followed by pressure cycle steam drive. Multisoaking was incorporated to assist in the early development of heat communication between injectors and offset producers and to accelerate bitumen production. This stage of the project has been very successful. Phasing of steam injection between clusters was scheduled to fully utilize steam generation capacity throughout the life of the project and to even out bitumen production from the field. After three full

years of operation, PREP continues to parallel PRISP in terms of performance, by meeting forecast bitumen production and OSR (Figures 6 and 7).

Plant facilities for the Peace River Complex were designed to degas produced fluids, separate produced water, and blend dry product with diluent to meet pipeline specs (Figure 8). Since the bitumen gravity is roughly the same as water, diluent is also added at the plant inlet to allow more effective processing. All produced water is injected into disposal wells completed in the Leduc D-3 reef, while softener regeneration back-wash is segregated and disposed of into the Mississippian Debolt formation.

A number of changes have been made to both the field and the process side of the Peace River operation during the past three years, to improve efficiency and to reduce operating costs. Some of the more significant changes are described in the following sections. It is an ongoing process, driven by economics, improvements in technology, and changes in environmental guidelines.

Field Improvements:

Well Testing: The single most important improvement in the field was made in the area of well testing. Three-phase test separators were included in the design of PRISP, with diluent addition upstream of each separator to assist oil/water separation. This system has operated well and with good accuracy as reflected in PRISP monthly bitumen allocation.

PREP design, on the other hand, utilized two-phase test separators located at each production pad. This design was chosen as it was uneconomic to pipe diluent to each production pad. However, it became evident that this system was not capable of providing the test accuracy desired for in-house reservoir performance monitoring and monthly production reporting. This was primarily the result of the use of manual grab samples for the determination of tar cuts. A two year investigative effort and a field trial resulted in the installation of AGAR Net Oil monitors (PREP only) to improve tar cut accuracy and repeatability.

The AGAR instrument uses microwave energy and internal calibration curves to continuously measure the water cut of a flowing liquid stream. Use of these units has eliminated the need for manual sample collection which has reduced the lab manpower requirements and greatly increased operating safety (Peace River produced fluids are sour and associated gas can be up to 10% H_2S). Furthermore, it has allowed well test frequency to be tripled (24 hr test to 8 hr test) providing better data on reservoir performance and bitumen production. Although there has been mixed industry response to this instrument, our use of the units has resulted in a significant improvement in well test accuracy. This is best demonstrated by the monthly bitumen proration factor which has improved to within 10% of unity (Plant/well test). The instruments have operated trouble-free since installation in June 1989 and represent a substantial operating cost saving.

Steam Foam Project: In 1987, a project was initiated to evaluate the use of a steam additive to assist the recovery process. The objectives of the project were to:

- demonstrate that stable foam can be generated in-situ under a range of typical Peace River reservoir operating conditions,
- demonstrate that steam foam can act as a divertant to redirect steam from the swept zones into higher bitumen saturation areas and improve short-term tar production rates and long-term recovery efficiency, and
- demonstrate that a surfactant injection operation can be safely implemented and maintained, with minimum impact on field personnel and facilities.

Considerable numerical reservoir simulation was carried out to evaluate the potential benefit in terms of overall bitumen recovery. Indications were that improvements in recovery of as much as 10% could be achieved through successful application of steam foam. Surfactant addition was piloted at PRISP starting in May 1988 for a period of four months. Indications at surface were that foam was generated in-situ as evidenced by an increase in injection pressure at those wells used in the pilot. The overall effect of surfactant injection on bitumen recovery will not be known until completion of the current blowdown phase and subsequent data analysis.

Plant Improvements:

Debottlenecking: Initial operations indicated severe limitations in the areas of heat integration and fluid hydraulics. Continuous monitoring and ongoing optimization efforts such as piping modifications, exchanger cleaning and chemical optimization have resulted in an increase in plant fluid handling capacity to over 10,000 m^3/d (approximately 125% of design). The ultimate capability of the plant is still unknown since higher processing rates have not been required to date.

Performance of one of the PREP water disposal wells has exceeded design expectations (the second well is a backup and has not been used). Despite early difficulties related to produced oil and solids contamination, initial injectivity levels have been routinely restored by acid clean-up and injection in excess of 8500 m^3/d has been sustained (130% of design). With improvements to disposal fluids filtering, no clean-ups have been required over the last full year of operation.

Reliability: PREP boiler on-stream time was an area targeted for improvement based on initial

performance (0.95 on-stream factor). The relatively high boiler downtime was due to a combination of factors including problems with minimum flow through boiler feedwater pumps and instrumentation logic. Several modifications have been made to improve on-stream time. These include process and instrumentation changes to smooth out boiler operation and efforts to improve reliability of the primary high pressure boiler feed water pumps (rework and development of maintenance / installation procedures, replacement of minimum flow protection system etc.). As a result, the average boiler service factor has been improved to roughly 0.98. The boilers have demonstrated design steam production capabilities, but at above design heat release. This has resulted in localized overheating of the economizer section and abnormally high radiant section tube stresses. Replacement of the PREP boiler economizer sections is presently underway. The new economizers have been designed to accept higher temperatures from the radiant section, to accommodate the eventual reuse of produced water and to allow more efficient utilization of sour produced gas.

Loss of diluent (gas condensate) light ends to the plant vapour recovery system was an area of initial concern. The effect on the operating cost was considerable since losses as high as 5-10% of the injected volume were experienced. Through careful monitoring and ongoing optimization work, diluent losses have been reduced to less than 1% of the produced bitumen volume. Elimination of diluent injection upstream of the degasser and a new higher-quality diluent source account for much of the noted reduction. Modifications to the plant vapor recovery system also contributed since this allowed for continuous recovery of light ends. The changes implemented to control these losses have significantly reduced the plant operating cost.

Performance of the high pressure disposal water injection pumps was poor during the first two years of operation. Multiple failures of these pumps resulted in several instances of forced cut-back of field production. Efforts to improve disposal water quality and pump maintenance and overhaul procedures have resulted in a dramatic improvement in pump reformance (no failures over the past year of operation). Hard facing of the pump cartridges and mechanical modifications are expected to double pump life (est. 2 - 3 years).

The above represent a few areas where the ongoing efforts to improve efficiency of both the field and plant operation have resulted in a significant reduction in overall operating cost since the start-up of PREP.

Safety: Safety improvements also constitute an ongoing effort. As noted earlier, one impact on improved safety was the elimination of manual samples for well test tar cut determination. While this was not hazardous in the first two years of PREP operation, manual sampling became a potential risk to the operators as temperatures increased and the fluids became more volatile and sour.

A number of routine tasks performed at many of Shell Canada's field operations, including the Peace River Complex, require the operations and maintenance staff to wear self-contained breathing apparatus (SCBA). In view of this and in response to redeveloped NFPA (National Fire Protection Association) regulations in the United States, a major company review of self-contained breathing apparatus in use at field locations was performed. Although the changes in the NFPA regulations are not binding in Canada, Shell Canada felt they provided guidelines for better protection of field staff. As a result, all SCBA units were replaced company-wide in 1989 including 65 units at the Peace River Complex (cost to the Complex alone was $300,000). The new units offer twice the air supply capacity of the replaced units and fully meet Canadian safety legislation.

As a result of recent changes in Canadian legislation covering the use of protective clothing, Shell adopted the use of NOMEX outerwear as the standard for fire-retardant clothing. Although several less expensive options were available, NOMEX outerwear was selected due to its superiority over other acceptable options. Guidelines were also issued regarding fire-resistant inner and winter clothing.

In addition to the above initiatives, Shell Canada has adopted the International Loss Control Institute (ILCI) system of safety management. Its purpose is to ensure a consistent and comprehensive set of standards is in place for safety procedures and the monitoring of safety performance. The system is divided into 20 elements including leadership and administration, training both management as well as employee, and off-the-job safety to name but a few. Effectiveness of the system is measured by annual safety audits, through compliance with procedures and frequent checks on the levels of understanding. Shell believes that through the use of ILCI, overall safety and loss control awareness can be increased leading to improved health, safety and environmental protection.

The Shell Peace River Complex has an excellent safety record and endeavors not only to maintain a safe working environment but also to meet and surpass changes in safety technology and legislation. This is reflected in the 1.4 million manhours worked without a lost-time accident reached in July, 1989.

Future Developments:

Work is also underway to meet the new environmental challenges facing the industry. Two areas with specific application at Peace River are

produced solids (mostly sand and scale) handling and disposal and produced water recycle.

The produced solids are recovered from PREP separators and treaters in the form of a dilute sludge. Entrained gas is then flashed off and the free water and oil are separated. The remaining 'concentrated' sludge is transferred to a covered concrete holding pit containing steam heating coils. Further oil and water are recovered from this tank as they separate due to the effects of heat and gravity and are then reprocessed. The residual solids are then transferred to a clay-lined solids pit for long-term storage. Regular groundwater monitoring of the area has shown this to be an environmentally secure storage means. To date, the average annual solids production is 60 tonnes, or 38 m^3. This is far less then originally included in the PREP design and is not expected to increase significantly in the years to come. As a result, the storage capacity of the solids pit at the current solids production rate is in excess of 500 years.

Shell recognizes that in spite of the low volume of produced solids, it is ultimately desirable to produce a cleaner solids residue. Ongoing research effort has been directed towards the reduction of solids volumes. A more effective method of deoiling and dewatering the solids to make them suitable for ultimate disposal has been pursued. The process has been divided into three components:

- conditioning oily produced solids to alter surface wettability characteristics and aid deoiling,
- separation of hydrocarbon phase using conventional gravity separation means, and
- dewatering of residual solids, again using conventional means as necessary.

The research effort is not complete at this time, but initial results are encouraging as cleaner solids have been produced leaving a residual oil/water mixture that can then be reprocessed.

Produced water recycle is a part of the long-term Peace River strategy. Shell recognizes that water reuse will aid fresh water conservation and have a positive environmental impact on deep well water disposal.

The initial target for PREP was 30% water recycle by 1990. Ongoing research has shown this to be an unrealistic objective as the development of a suitable water recycle process has been more difficult than originally thought. Shell's efforts in this area have focused on ion exchange softening without silica removal. This process was chosen as it concentrates the 'contaminants' in the produced water for easier disposal and avoids generation of residue solids such as lime sludge. Together with AOSTRA and Pecten Canada Limited, a produced water recycle pilot was designed and operated between 1987 and 1988 at the Peace River Complex to test out the proposed process. Problems specific to steam generator operation were encountered during the pilot.

Ongoing research activity focuses on the mechanisms of silica scale formation and steam generator erosion/corrosion. This effort will continue the commitment to develop technology for produced water recycle with the objective of an acceptable process in the not-so-distant future.

Summary:

The ongoing effort at the Peace River Project has been to improve the bitumen recovery process, both from the reservoir/production standpoint and plant operation. Through a combination of bitumen production and overall process efficiency increases, and reduced energy requirements, the estimated operating cost has been reduced by approximately two thirds from that during the first full year of operation. Further reductions are possible through continued optimization of the plant facilities and innovative solutions to both technical and operational challenges. Future expansions will benefit from the ongoing improvement effort as the new plants will be designed to run cleaner, be more energy-efficient and operate in safer co-existence with the surrounding environment.

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FIGURE 1

FIGURE 2

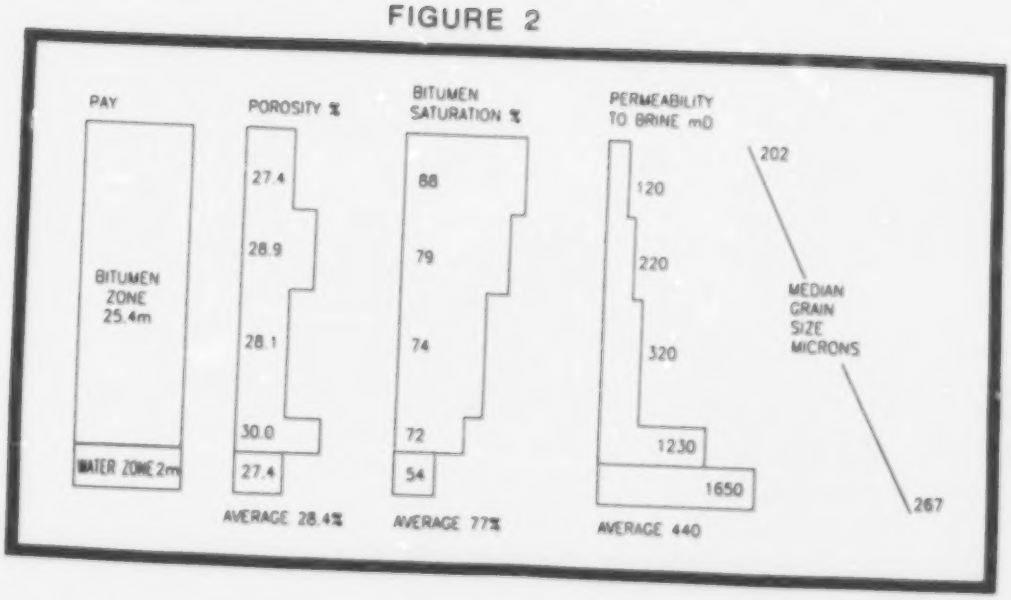


FIGURE 3: PRISP Cumulative Recovery Efficiency

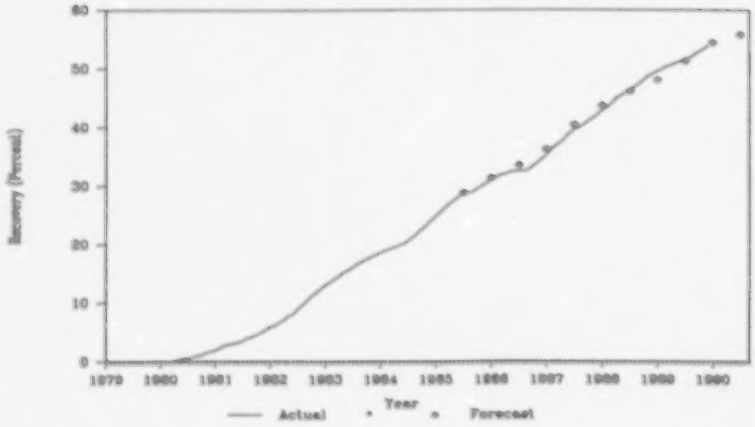


FIGURE 4: PRISP Cumulative Oil Steam Ratio

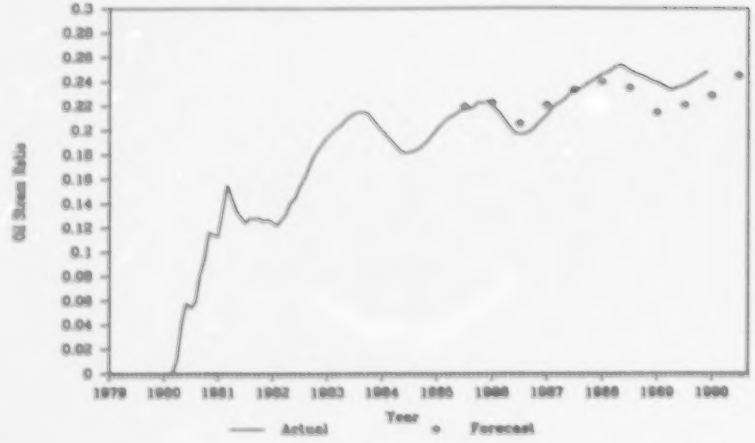


FIGURE 5: Well Layout

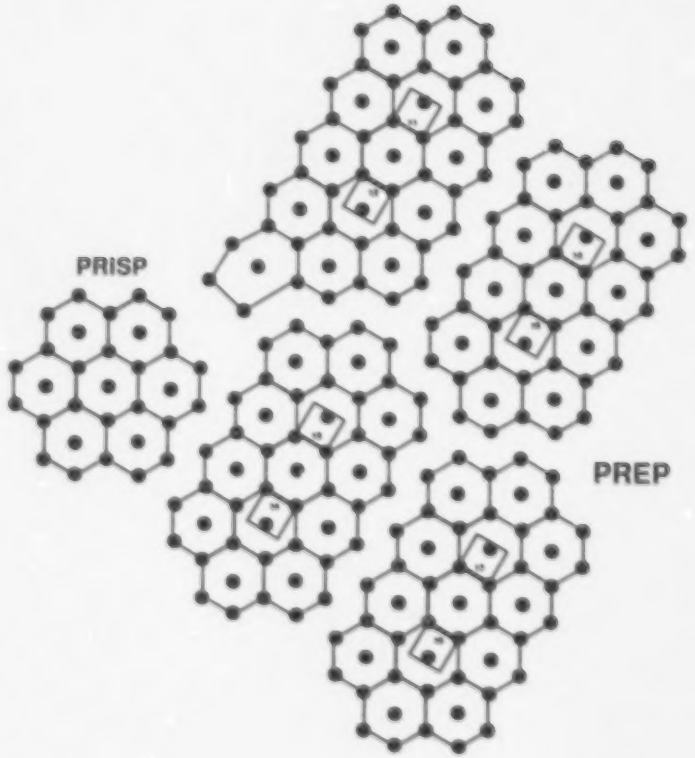


FIGURE 6: PREP Cumulative Recovery Efficiency

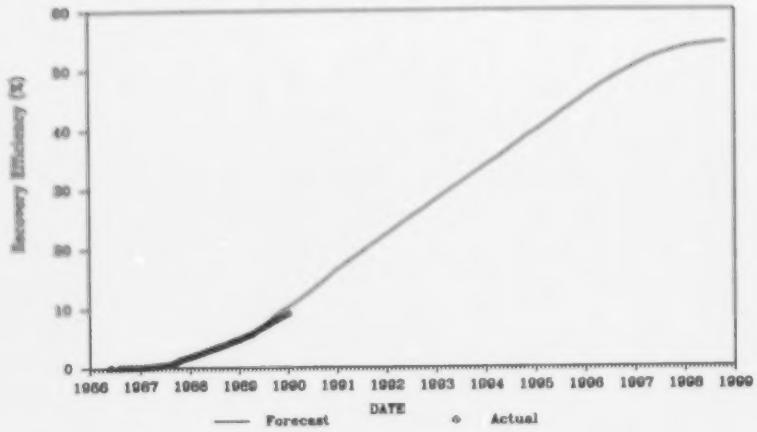


FIGURE 7: PREP Cumulative Oil Steam Ratio

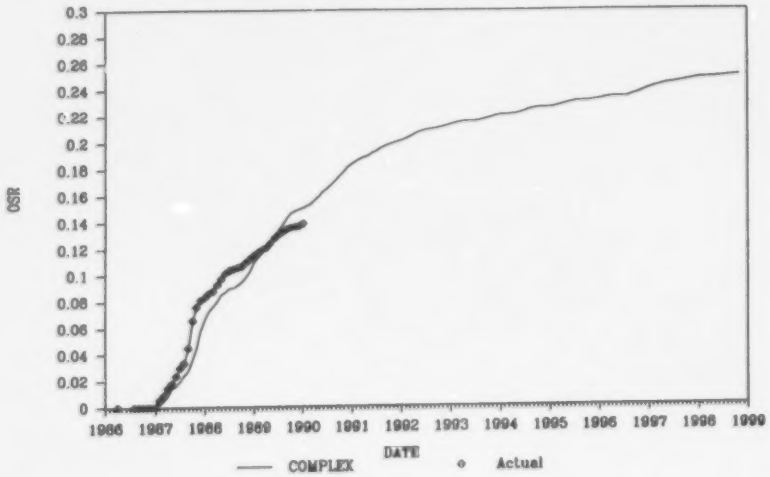
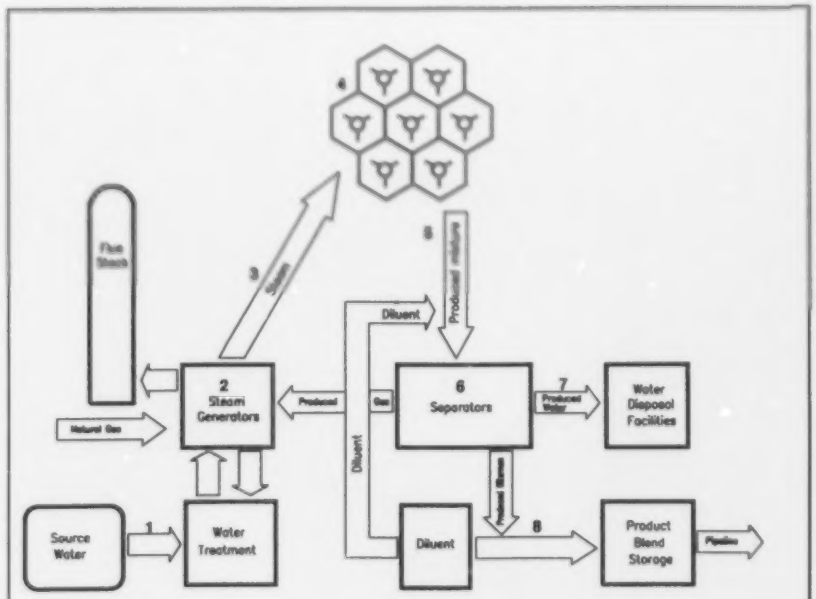


FIGURE 8: Process Schematic



1. Source water is treated and converted to high pressure steam.
2. Steam generators are fueled by natural gas.
3. High pressure steam is injected into the wells and oil sands formation.
4. Well patterns consist of inverted seven spot patterns. Field development consists of 187 production wells and 60 injection wells (PRISP and PREP).
5. Produced mixture of bitumen, water and gas from field is piped to plant for processing.
6. Separation of water, produced gas and diluted bitumen.
7. The water produced with the bitumen is treated and reinjected into a disposal zone below the oil sands section.
8. Produced bitumen is mixed with a diluent and transported to market via pipeline.

Performance Evaluation Of The Countess Fireflood Project

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Abstract. The 16 ha inverted five spot fireflood pilot project operated by PanCanadian Petroleum Limited, and jointly owned with LL&E Canada Limited in the Countess Field in Southeast Alberta, was initiated in 1983 to evaluate the fireflood process in a waterflood Glauconitic sandstone reservoir of the Upper Mannville Group containing 28°API oil. The pilot is still continuing and is expected to be terminated in 1991. The Alberta Oil Sands Technology and Research Authority has supported this pilot by funding an extensive research program aimed at providing pertinent data and improved technology which could improve fireflood operations and assist in planning future commercial projects.

The paper reviews the pilot project and provides a performance analysis of the process application in the Countess "B" Pool. The paper also serves to update the previous technical paper presented on the project.

To date, the pilot project has demonstrated that the Countess "B" Pool, a waterflooded reservoir, can be fireflooded successfully and the combustion process can propagate efficiently in this pool and displace most of the residual waterflood oil. The proposed pilot expansion and future fireflood development in this pool are also discussed.

INTRODUCTION

The Countess Upper Mannville "B" Pool (Figure 1) is part of the Countess-Lathom trend in Southeast Alberta. The Glauconitic sandstones of Countess "B" were discovered in 1965 and contain 28°API oil. Waterflooding commenced in 1973, and the waterflood recoverable reserves will be approaching their economic limit in the near future. The pool is operated by PanCanadian Petroleum Ltd. and jointly owned (50%) with LL&E Canada Ltd.

In 1983, a 16 ha inverted five spot fireflood pilot project was initiated in the Countess "B" Pool to evaluate the fireflood process. The Pilot is still continuing and is expected to be terminated in 1991.

The Alberta Oil Sands Technology and Research Authority (AOSTRA) has supported this pilot by funding an extensive research program. The agreement was signed in August 1983. In exchange for the project data, AOSTRA agreed to carry out a parallel research program which is directly focused on the needs of the pilot. The main objective of this research program is to provide pertinent data and improved technology which could improve the current operations and assist in planning future commercial projects.

RESERVOIR ASPECTS

Reservoir aspects of the Countess "B" Pool were previously reported[1]. The sandstones of the Countess "B" are part of the "Glauconitic" of the Upper Mannville Group. Oil production is from a number of channel sands, as shown in Figure 1. The largest of these channel sands is called Countess "B" Part II, where the fireflood pilot is located, and the average reservoir properties are:

• Depth	1080 m
• Net Pay	8 m
• Porosity	25%
• Permeability	800 md
• Reservoir Pressure	9.6 MPa
• Initial Oil Saturation	78%
• Oil Saturation at Start of Fireflood	50%

A number of combustion tube tests were performed at the University of Calgary prior to the pilot initiation. Description of the combustion tube tests and results obtained were summarized previously[1]. Under the Research Agreement with AOSTRA, additional combustion tube tests were conducted to study the effect of enriching air on the combustion process. In all of these tests rock material and fluids from the Countess "B" Pool were used. The major conclusion obtained from these

tests was that the Countess "B" Pool is a good candidate for fireflooding.

PILOT DESCRIPTION

The Countess "B" fireflood pilot, shown in Figure 1, consists of one inverted five-spot pattern comprising four existing producing wells and one air injection well. The four producers are located at:

04-16-19-16 W4M
01-17-19-16 W4M
16-08-19-16 W4M
13-09-19-16 W4M

The air injection well is located at A4B-16-19-16 W4M. It was drilled and completed initially as a producer in 1982. The well was placed on production in April 1982 and shut-in July 1982 due to increasing water cuts. The well was converted to an air injection well. A pressure core was cut during the drilling of the well A4B-16-19-16 W4M to ascertain that the oil saturation in the injection well was adequate for ignition. A low water loss fluid was used while penetrating the formation to minimize invasion and formation damage. The air injection well was completed with a 178 mm (7") casing to allow a 114 mm (4 1/2 ") heat-shield to be run during the ignition to ensure containment of the flame within the shield.

The pilot location had been waterflooded extensively, and the existing pilot producers were rapidly watering out. The pilot location had no bottom water or gas cap present. To establish the average oil saturation at the start of the pilot, carbon/oxygen logs were run in mid 1982. The average oil saturation in the pilot area from these logs was found to be 43.4%. It is believed that the average oil saturated calculated is lower than actual, due to the limited depth of investigation of this tool and the large volume of water produced from these wells. It is estimated that the average residual oil saturation in the pilot at the start of fireflood operations in January 1983 was about 50%.

The main objective of the pilot was to evaluate the fireflood process as a means for tertiary oil recovery in the Countess "B" Pool. Specific objectives and further details on the pilot description were reported previously[1].

SURFACE FACILITIES

The main air compressor was a 600 HP variable speed, D.C. electric driven, four-stage reciprocating, synthetically lubricated compressor with interstage cooling and an after-cooler to cool the discharged air to 66°C (155°F). Two 200 HP screw booster compressors compress air from atmospheric to the inlet pressure of the main compressor. The main compressor is rated at 56,630 m^3/d (2 MMscf/d) with a maximum discharge pressure of 24,000 kPa (3500 psig). During the first three weeks after ignition, a rental compressor was on site as standby to ensure continuous air injection.

The produced fluids are piped in flow lines, as shown in Figure 2, through a rotary selector valve, either to a three-phase test or a group separator (horizontal gravity settler type). The produced gas is currently flared or vented from the flare stack. The produced emulsion from the separators is sent to a separate treating facility which handles the fireflood production only. Emulsion breaker, along with biocide, corrosion inhibitors and defoaming chemicals, is injected at the wellheads of the four pilot wells.

PROJECT PERFORMANCE

Details pertaining to ignition of the Countess "B" Pilot were previously reported[2]. Significant problems occurred during ignition due to injection air at higher pressure than previously used which was extremely corrosive, inadequate composition of the completion fluid under the prevailing corrosive environment, and difficulties when operating under extremely cold weather conditions. However, ignition was successfully completed on the third attempt during the last week of January 1983.

Prior to ignition, the air injection rate was about 7500 m^3/d at an injection wellhead pressure of 17.8 MPa. During ignition, the wellhead pressure dropped to 8.3 MPa and remained at this level to April 1983. Air injection was increased gradually and reached the maximum design rate of 56,000 m^3/d by the end of 1983.

Production history of the Countess "B" Fireflood Pilot indicates that there is no noticeable production decline observed to date since starting the project in 1983. Oil production rates fluctuated between 25 and 35 m^3/d. Fluctuations were mainly due to the operational problems encountered. Although the pilot area was supported by both waterflood and fireflood over this time, the pilot wells suffered no decline in production or increased WOR while non-pilot wells did. The pilot WOR and GOR history is shown in Figure 3. A portion of the total produced oil is incremental due to the fireflood process. This includes oil displaced ahead of the firefront from the burned volume of the reservoir, oil displaced by steam and hot water banks, and oil displaced by combustion gas drive.

Estimates of incremental oil recovery are complicated by the fact that the unconfined inverted five-spot pilot is located in the middle of an active waterflood project. In addition, the many operational changes made to both the fireflood and waterflood projects add further complications. As a result of the operational problems which will be discussed later, a portion of the displaced oil by firefront has not been recovered to date.

incremental recovery is estimated to range from 10 to 20% of the OOIP.

Air and combustion gases generated have been contained within the pilot area, and no combustion gases have been detected in the wells offsetting any of the pilot producers. To the end of 1989, cumulative combustion gas recovered was 90% and cumulative oxygen utilization was 97%. To the end of 1989, cumulative combustion gas composition was: 87.1% N_2, 11.8% CO_2, 0.8% O_2 and 0.3% CO. The level of H_2S in the produced gas has been under 10 ppm. Currently, the pilot produced gases are vented in the flare stack, which is capable of handling up to 200 ppm H_2S content without exceeding the prescribed ground level H_2S concentration of 0.01 ppm.

The cumulative burned volume to the end of 1989 represents about 20% of the enclosed pilot volume. Advancement of the burned zone in each quadrant is shown in Figure 4. The size of the burned zone in each quadrant is assumed to be proportional to the quantity of combustion gas produced at each pilot producer.

In early 1985, a post combustion core well was drilled approximately 50 m to the S.E. of the air injection well. The well was cored over the interval 1077 to 1092.4 mKB (15.4 m). The peak temperature encountered while coring was 100°C. A temperature of 42°C was recorded at 5.5 m above the top of the sand. Core analysis and correlation to the logs indicated that at least one-third of the core recovered was completely burned. This burned zone lies mainly in the middle of the sand. Some unburned coke residual was present in the remaining portion of the cored interval of the sand with some oil stain.

The mineralogical study of the post combustion core, conducted by the Alberta Research Council[6], indicated that the temperature of the firefront probably did not exceed 400°C (range 300–400°C). This was based on the formation of alunite and smectite found in the post combustion core. The coring results indicate that the Countess "B" Pool will support combustion, and much of the oil left after waterflooding is effectively displaced.

Major operating problems encountered could be summarized as follows:

1. ***Early Oxygen Breakthrough.*** In late 1986, the well EX 04-16 was shut-in when oxygen concentration in the produced gas exceeded 4%. Production recommenced in June 1987 with not oxygen, but after four weeks oxygen level rose to 4% and the well shut-in again.
2. ***High Oxygen Concentration in Produced Gas in the Latter Stages of Fireflood.*** This is mainly due to air bypass of the combustion front in areas where air flux is not sufficient to sustain efficient combustion. Shutting-in air injection for short periods has been found to help in controlling oxygen.
3. ***Alternate Air/Water Injectivity.*** Many attempts to continue alternate water/air injection, which included injecting various slug sizes of water, were made. The air injection pressure continued to increase following injection of each water slug. It was found that air injectivity can be regained by acidizing or to a lesser extent by blowing back the air injector. The observed injectivity decline is thought to be mainly due to partial plugging of the reservoir around the wellbore by particulate matter.
4. ***Operation in the Middle of an Active Waterflood.*** The surrounding waterflood scheme caused a pressure gradient across the pilot which resulted in an asymmetric burned zone. To alleviate this, back pressure was held on some wells to encourage air movement to other directions, resulting in production losses for long periods.
5. ***Corrosion.*** Rapid pitting and general attach of bare carbon steel production well components by the produced emulsion resulted in frequent replacement of tubing, flowlines, pumps and rods. The worst corrosion occurred in those wells which were producing oxygen and high water cuts. The most severe corrosion occurred on the inside of the production tubing in the region above the bottomhole pump. Rapid corrosion was also experienced in the surface flowlines, particularly at the elbows where flowing fluids impinge on the large diameter side of the elbows.

   Downhole inhibition by batch application and recirculation were tried unsuccessfully to control production well corrosion. A plastic coating applied to the rods and the inside of the well tubing and flowlines appears to be effectively controlling corrosion. Cathodic protection was used successfully to control external corrosion on the casing. It is unclear if the cathodic protection gave protection to the inside of the casing.

   Bare carbon steel performed poorly in air and water injection service. Internally plastic-coated well tubing and flowlines performed well.

FUTURE DEVELOPMENT

The fireflood pilot expansion in Countess "B", Part II, is planned for 1990 as shown in Figure 5.

This includes two inverted spots and requires two new air injection wells (12D-09 and 13B-09). These two spots include seven existing wells (09-08, 16-08, 11-09, 11C-09, 12-09, 13-09 and 13C-09).

The life of the proposed expansion is expected to be 8 to 10 years and air will be injected for the first 6 to 8 years followed by water injection for about 2 years. The expansion is assumed to occur in md 1990.

In addition to the proposed two spots, there are seven additional spots which could be converted to fireflood in the future. These seven additional spots are shown in Figure 5. Potential incremental oil of these spots is estimated at 224,000 to 315,000 m^3 (1.4 to 2.0 MMbbl). The total expected incremental oil for the proposed and potential expansion in the Countess "B" Pool ranges from 228,000 to 379,000 m^3 (1.8 to 2.4 MMbbl).

The objectives of the proposed pilot expansion are as follows:

1. The main objective of the pilot expansion is to evaluate the fireflood process as a means for tertiary oil recovery and gather the necessary information required to evaluate the economics and design for commercial application of the process in the Countess Field.
2. Efforts will be made to resolve some of the operating problems encountered during the pilot phase, in particular:
   - early oxygen breakthrough experienced with one pilot producer;
   - controlling oxygen level in the produced gas, particularly in the latter stages of fireflooding;
   - determination of incremental fireflood oil without interference from waterflood.
3. Experiments planned in this phase of fireflood operations:
   - ignition of the reservoir using chemical methods will be considered;
   - operating the reservoir at lower pressure to evaluate the impact on the process efficiency;
   - optimization of injection and production rates with the help of modelling;
   - identification of any other operating problems not encountered in h pilot phase and development of solutions;
   - continuation of equipment evaluation;
   - determination of economics of commercial application.

CONCLUSIONS

The Pilot Project has clearly demonstrated that the Countess "B" Pool, a waterflooded oil reservoir containing 28°API oil, can be fireflooded successfully and the combustion process can be maintained on the pilot spacing of 8 ha/well and can effectively displace much of the residual oil left after waterflooding. The proposed pilot expansion as described in this paper will properly complete the process evaluation for future commercial application in the Countess Field.

ACKNOWLEDGEMENTS

The author wishes to express his appreciation to PanCanadian Petroleum Limited, LL&E Canada Ltd. and the Alberta Oil Sands Technology and Research Authority for their permission to present this paper. The dedicated support and cooperation of the field staff are greatly appreciated. Also the contribution of many of PanCanadian's staff to this project is greatly appreciated.

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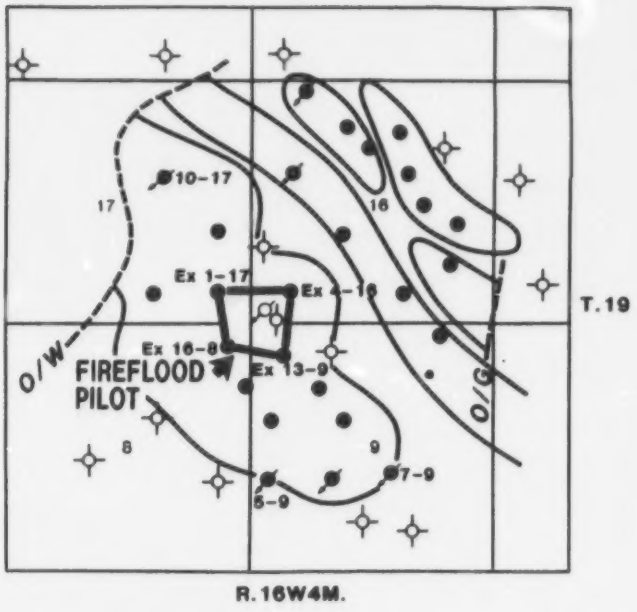

COUNTESS B FIREFLOOD PILOT

- AIR INJECTION WELL
- PRODUCING WELL
- POST COMBUSTION CORE WELL
- WATER INJECTION WELL
- ABANDONED WELL

Figure 1

SURFACE FACILITIES
COUNTESS "B" FIREFLOOD PILOT

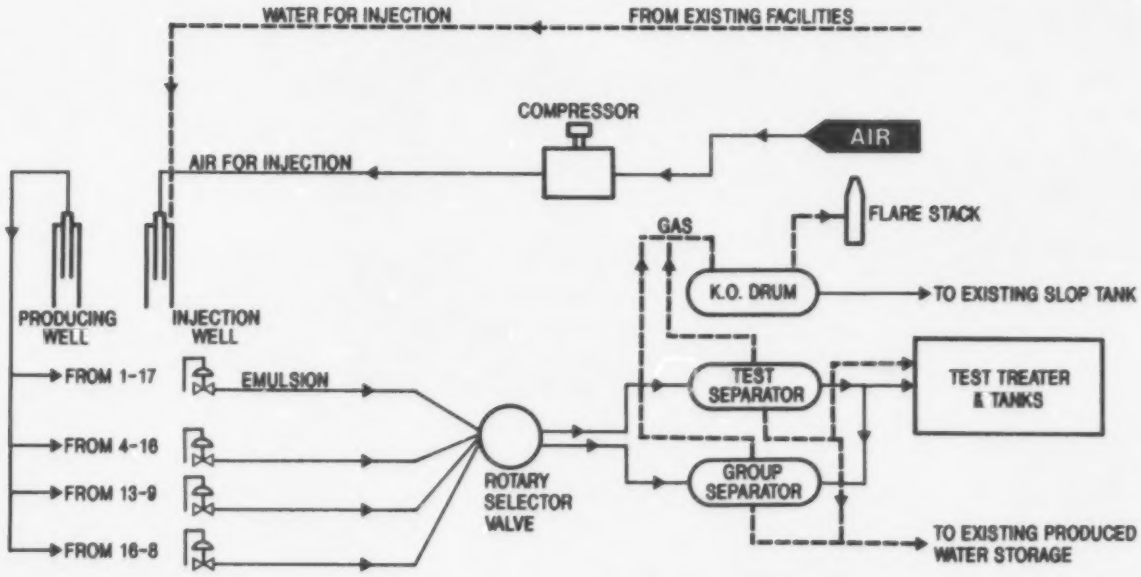

Figure 2

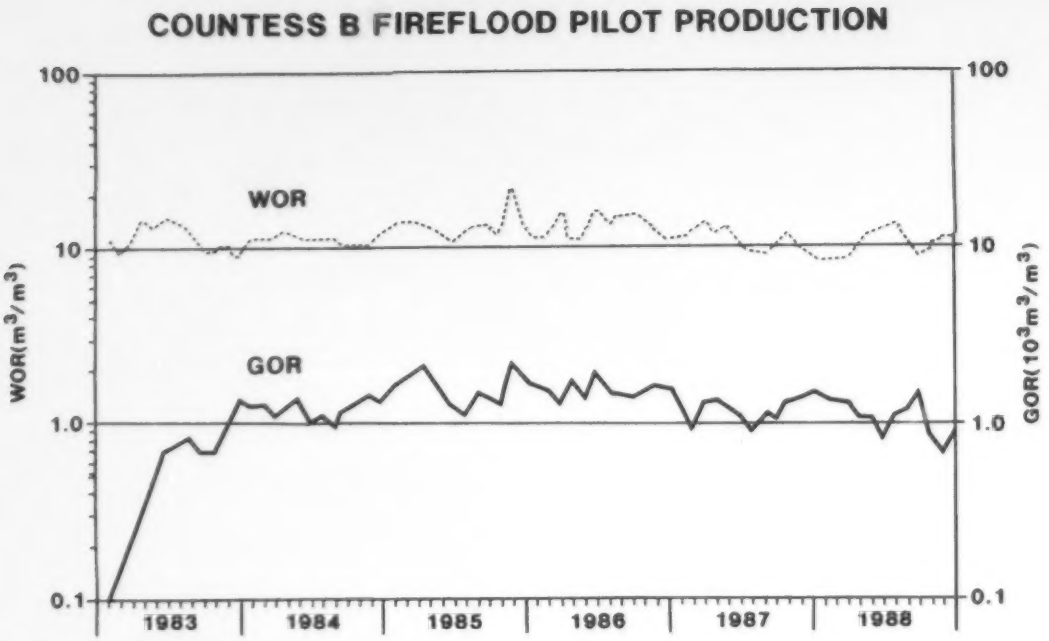

Figure 3

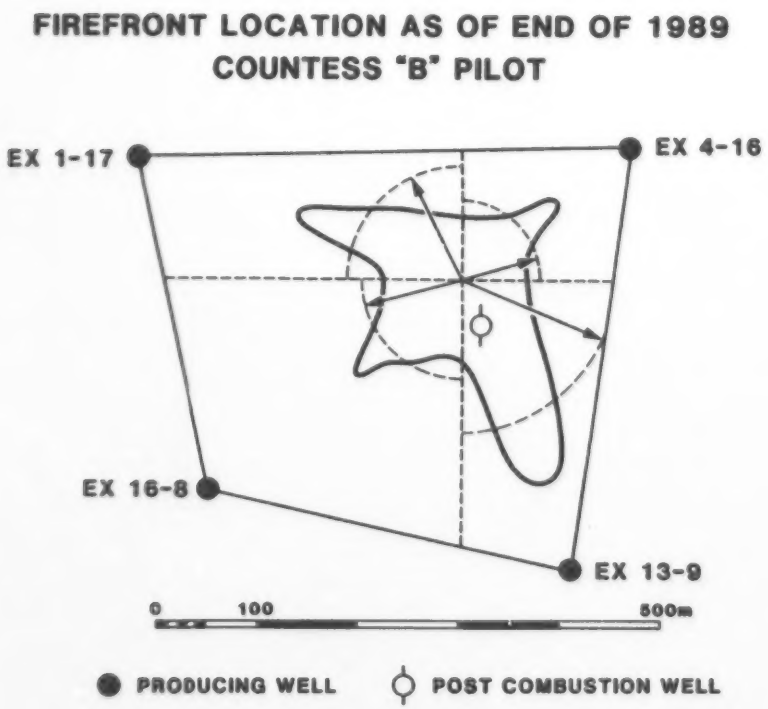

Figure 4

COUNTESS 'B' POOL

CURRENT AND POTENTIAL DEVELOPMENT

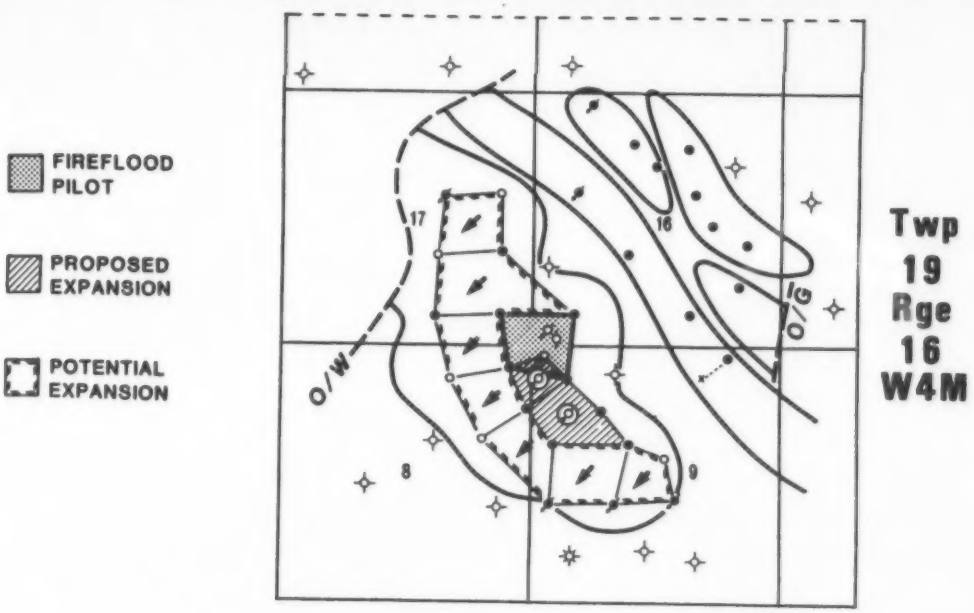

Figure 5

AWACT: Anti Water Coning Technology

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Abstract. It is estimated that over 50% of Alberta oil fields experience excessive water production, resulting in lost recovery from early abandonment of wells. To minimize the adverse effect of water production, operators have tried to physically block the water through injection of cement, polymer, foam, and other chemical agents. These techniques generally have met with mixed success and have the reputation of being unreliable.

AEC and Westcoast Petroleum Ltd., with technical and financial support from Alberta Oil Sands Technology and Research Authority (AOSTRA), have developed a simple process, called Anti Water Coning Technology (AWACT), for inhibiting water production and have tested its applicability in a heavy oil water coning environment. Laboratory tests and reservoir simulation have been used to develop a theoretical basis for the process mechanisms. This paper describes the process and treatment procedure and shows long-term field results to demonstrate both acceleration of production and increase in recovery.

AWACT is a commercially viable recovery process for the South Jenner field, where AEC plans to stimulate over 120 wells as water production reaches unacceptable levels. This program will be initiated in early 1990.

INTRODUCTION

Water coning occurs as oil production proceeds and the underlying water rises upward in a cone shaped zone to the production perforations. Once the less viscous water reaches the perforations, it is produced in preference to the more viscous oil. The eventual result is that the water-to-oil ratio in the production well reaches an uneconomic level.

Water coning is particularly evident in South Jenner, a Glauconitic heavy oil reservoir, located in the northwest corner of the Suffield Military Range of south eastern Alberta. This reservoir is an estuarine channel deposit, located at a depth of 1000 m and underlain by a thick, moderately active aquifer. The oil bearing portion of the reservoir can be up to 38 m thick with permeability in excess of 1 μm^2. The oil has a specific gravity of 0.98 and at reservoir conditions, a viscosity of 100 mPas. Core analysis shows a high ratio of vertical to horizontal permeability. Also, there are no apparent impediments to flow in the vertical direction.

Because primary recovery is controlled by water coning, the inter well spacing was reduced to 100 m (1 ha) to match the lateral extent of the water cone. In this way, estimated recovery was increased 16 fold to 24% of the original oil in place. Wells were also partially penetrated into the production zone to delay coning and improve primary cement quality.

In South Jenner, the detrimental effects of water coning are being mitigated by AWACT, a process wherein a non-condensible gas and chemical mixture are injected into a reservoir to reduce water production and increase oil recovery. Although the name, AWACT, implies this stimulation is only for water coning situations, the process has application to any oil well which produces too much water. AEC presently uses 90% water cut as a criterion for selecting AWACT candidates.

AWACT, originally patented in 1985[1], was developed from observations and analysis of data generated from the Suffield Heavy Oil Pilot (SHOP)[2]. SHOP was a project to investigate fireflooding as an in situ recovery method in a reservoir which had underlying water. During the course of the fireflooding project, it was observed that water production at the pilot wells was much less than at the surrounding non-pilot production wells.

Subsequent laboratory and field testing led to an understanding of the process mechanisms. The combination of gas and chemicals alters the three phase relative permeability so oil is preferentially produced over water. The presence of free gas also reduces the residual oil saturation, thereby mobilizing additional oil. Several additional patent applications relating to AWACT have been filed by AOSTRA based on the laboratory and field testing programs.

The AWACT process has been tested in 23 wells and has been economically successful in the majority of these tests. AOSTRA is now encouraging

application of this technology in Alberta, where it is estimated that as many as half the oil reservoirs may be affected by excessive water production. Single well stimulations may be conducted for a nominal licence fee, and AOSTRA will consider financial support where extension of the technology is experimental in nature.

BACKGROUND

A literature survey was conducted in 1986 to identify published work on the use of gases plus additives to control water coning. At that time, Alikham[3] reported that researchers were investigating methods to inhibit or prevent water coning. These methods included cementing, horizontal fracturing followed by cementing, the use of polymers to reduce water mobility, the use of surface-active agents, and electro-osmosis. Alikham considered those methods to be of "limited efficiency at best" when applied in the field.

The AWACT process was an outgrowth of observations made at the SHOP project where water coning was reduced at production wells in a fireflood pilot. Mobil[4] and Texaco[5] report, for their firefloods in reservoirs with underlying water, observations with respect to water coning control similar to those from SHOP.

The use of carbon dioxide in a huff 'n puff mode in reservoirs with underlying water has been reported by Stright[6] and Simpson[7]. Results confirm that water coning may be controlled by gas injection into the reservoir.

AWACT THEORY

Incremental oil recovery from AWACT is attributed to a reduction in residual oil saturation caused by gas injection and the reduction in relative permeability which occurs when a third phase is present in porous media. Other lesser mechanisms involved include water displacement by gas, gas drive, viscosity reduction and oil swelling.

In 1970, Schneider and Owens[8] conducted experiments on the effect of gas saturation in waterflood tests. For both oil and water wet core, they found a reduction in residual oil saturation with increasing gas saturation.

Sayyouh[9] also reported an improvement in oil recovery caused by the establishment of a free gas saturation in the reservoir. He theorized that the reduction in residual oil saturation in a three phase system is due to interfacial tension effects. Since gas oil interfacial tension is less than that of gas-water, the fluids will arrange themselves in a minimum energy relationship, whereby the gas molecules enclose themselves within oil globules.

Three phase relative permeability theory implies that both the wetting and non-wetting phases will have a relative permeability which is a function of their own saturation. However, the intermediate wetting phase is subject to interference from the other fluids and will have its flow capacity reduced. In a core with intermediate wetting character, one would expect both oil and water relative permeability to decrease with the addition of gas. When the reservoir is oil wet, only the water relative permeability will be reduced.

Schneider and Owens[8] observed that, for both oil and water wet core, the presence of gas caused a significant reduction in water relative permeability, while the oil relative permeability was only moderately reduced when the rock was water wet. They also reported that gas did not change the wetting character of the core[10].

Stone[11,12] conducted three phase relative permeability experiments and developed two empirical equations to calculate three phase relative permeability from two phase gas-oil and water-oil displacement tests. This work assumed a water wet core. The principles adopted by Stone were used to develop an equation for an oil wet system which is shown in Appendix I. In this case, gas-water and water-oil displacement tests are used to calculate three phase water relative permeability. The results of this oil-wet Stone's Model II are shown in Figure 1 using South Jenner data. Using this model, a critical gas saturation of only 6% causes a significant reduction in water relative permeability.

LAB DATA

The Glauconitic reservoir at South Jenner exhibits neutral to moderate oil wetting. This is supported by extensive analysis of various tests conducted on native state core. Electrical resistance increases exponentially as water saturation was reduced, indicating a continuous oil phase. Oil spontaneously imbibes while water will not. A contact angle of 90° is required to match capillary pressure to oil-water transition zone thickness.

Following the observation of reduced water production at SHOP and the first successful AWACT tests, a program of laboratory testing was initiated to understand the process mechanisms more fully.

AOSTRA commissioned physical model testing of the AWACT process on sand packs at the Alberta Research Council. The injection of three different non-condensible gases (natural gas, nitrogen, and carbon dioxide) resulted in consistent reduction in water production.

To provide data for numerical modelling and confirm the process mechanisms, a series of core floods was conducted to simulate the saturation history in three regions of the reservoir: the oil zone, that portion of the oil zone in which water has coned, and the water zone. Core for these tests was cleaned, resaturated and aged according to

recommended procedures published by Mungan[13]. Results from wettability tests conducted before and after the core floods are shown:

Wettability Index	Before	After
USBM	−0.343	−0.389
AMOTT – water	0.336	0.035
AMOTT – oil	0.089	0.000

To simulate an AWACT treatment in the oil region, a restored core was subjected to a gasflood followed by an oilflood. At the end of the gasflood, the flow rate was increased from 2 cc/hr to 100 cc/hr. The relative permeability to gas is shown in Figure 2. The displacement was apparently sensitive to velocity, since oil recovery increased by more than 10% when the rate was raised to 100 cc/hr. A critical gas saturation of 3.5% was measured. Oil relative permeability is shown in Figure 3.

For the region subjected to a water cone, the core test proceeded with floods in the following sequence: waterflood, gasflood, oilflood, and second waterflood. This series of displacement tests simulated the formation of the initial water cone, subsequent AWACT treatment with clean oil displacing the injected gas, followed by the inevitable water cone. The oil relative permeability is shown in Figure 4. Of significance is the 7% pore volume reduction in residual oil saturation following the gasflood and the increased oil mobility during the second waterflood. Water relative permeability, shown in Figure 5, was lower after gas injection. These observations can account for both incremental oil production and an increase in oil cut.

To model the saturation history in the water zone, the core was first waterflooded to residual oil saturation to represent the oil-water interface. A gasflood followed by waterflood simulated the AWACT test, where it is expected that some injected gas will channel to the oil-water contact. The results from this test, shown in Figures 2 and 6, confirmed both the reduction in residual oil saturation and the critical gas saturation which was measured in the other tests.

In comparing results of the gas displacement tests, Figure 2, the gas relative permeability was much higher for gas-water displacement than for gas-oil. This is opposite to the findings of Schneider and Owens[8]. The oil relative permeability from the coned region and the oil region are plotted in Figure 3. When normalized to the same end point saturations, these curves would be similar, offering further confirmation of the reservoir's oil wetting character.

FIELD TESTS

Field tests at 21 wells have been conducted in the South Jenner Upper Mannville J pool and other miscellaneous Mannville reservoirs in the Suffield Military Range. In addition to confirming the process, field experiments were conducted to study the effect of multiple injection into the same well, changing the injected gas volume, treating wells from a central injector, changing the reservoir, and adding chemicals to alter wettability. Basic information for the wells which were treated as single well (cyclical) stimulations is shown below:

Well Name	Oil Pay (metres)	OOIP (10^3 m^3)	Gas Inj. (10^3 m^3)
14 –32 –19–8 W4M	11.0	69.4	160
11E –34 –19–8 W4M	10.7	20.7	57
11I –34 –19–8 W4M	14.9	29.2	51
14P –34 –19–8 W4M	19.5	28.8	54
14 –1 –20–8 W4M	12.2	141.4	158
3 –3 –20–8 W4M	16.4	33.0	202
6M –3 –20–8 W4M	25.2	46.1	50
12P –3 –20–8 W4M	18.4	32.3	99
13P –3 –20–8 W4M	26.9	59.9	54
3C –5 –20–8 W4M	6.0	8.0	56
1H –9 –20–8 W4M	12.8	27.8	85
4L –10 –20–8 W4M	29.0	48.1	411
1L –16 –20–8 W4M	18.0	44.1	298

Mechanical Design

An AWACT stimulation requires injecting a non-condensible gas down the annulus. For the Suffield tests, a skid mounted compressor with a liquid knockout drum was leased and installed at the wellsite with the discharge connected directly to the casing valve.

Low pressure gas was delivered to the compressor suction from one of two sources. The early tests used mildly sour solution gas which was conserved at the central cleaning plant or sweet shallow gas used as fuel at test satellites. Oil flowlines were purged and used to deliver low pressure gas to the compressor suction. For those wells which were not flowlined, a temporary surface flowline was run from a nearby shallow gas gathering system.

Where natural gas was not available, another operator trucked in cryogenic nitrogen with a vaporizer and heater. For low pressure reservoirs, one could also consider propane. The potential use of compressed air must be approached cautiously because of the explosion potential on flowback and the risk of low temperature oxidation in the reservoir.

With surface piping connected and bottom hole pump unseated, liquids were circulated from the well by injecting gas down the annulus and up the tubing. When gas returns were observed, the tubing valve was closed and, where programmed, chemicals were batched down the annulus. Gas injection continued at the highest rate possible until the prescribed volume was displaced. During all stages of injection, care was taken to avoid fracturing the formation.

After a nominal soak to equalize pressures, the well was gradually returned to production. For the first few days, only gas was produced, and rates were controlled to minimize velocity and sand production. Wells then started producing oil with no water. By the end of the first month, production and water cut had stabilized.

Original Gas Tests

The first AWACT treatment was conducted at 1L-16-20-8 W4M. This well, like most other South Jenner wells, produces on a harmonic decline which yields a straight line when the logarithm of oil cut is plotted against cumulative recovery. As shown on Figure 7, 1L-16 was expected to produce 7000 m^3 of oil or 16% of original oil in place. Declines were extrapolated to an oil cut of 4%, because it has been observed that beyond that point, many wells fall from the decline and rapidly water out.

The results from the injection of 300 10^3 m^3 of gas are also shown in Figure 7. Oil cut increased from 6% to 30% and, based on extrapolation of the well's decline, recovery is expected to increase by 35% to 9500 m^3. Only 25% of the gas injected was recovered. An apparent reduction in fluid productivity was observed within the first three weeks of production at which time the well stopped flowing and artificial lift was installed. Fluid withdrawal was controlled at 30 m^3/d to match the production rates prior to stimulation.

In the last quarter of 1986, 4L-10-20-8 W4M was produced at fluid rates of 140 m^3/d to stimulate the well by inducing gas from the nearby SHOP fireflood. The water cut increased from 93% to 100% and the gas rate did not change. Returning the well to its original rate of 40 m^3/d for several months failed to restore the oil production.

The test procedure from 1L-16 was repeated at 4L-10 during March 1987, and again rates were controlled to match prior long-term history. Because two wells adjacent to 1L-16 experienced gas breakthrough when that well was stimulated, the injection volume at 4L-10 was reduced to 200 10^3 m^3 of solution gas. As shown in Figure 8, the stimulation restored 4L-10 to an oil cut of almost 40% and oil recovery is expected to increase by 50%. The estimated primary decline shows some additional recovery had the high rate test not been undertaken.

In January 1988, a further 210 10^3 m^3 of natural gas was injected at 4L-10 to determine whether a second stimulation would provide an equal increase in apparent recovery. Neither incremental oil nor production increase was attributed to the second treatment. On the basis of this test and the operator's understanding of the process mechanisms, no other tests of multiple cycles were conducted. As discussed later in this paper, AEC now believes that recovery may be sensitive to injected gas volume and that the second cycle may be contributing to the high incremental recovery from this well.

Because the 4L-10 test was considered to be partially influenced by the fireflood, a test of repeatability was conducted at 3-3 using 200 10^3 m^3 of natural gas. Prior to gas injection, 3-3 had produced for eight months with an oil cut less than 4%, and the well was scheduled for conversion to water disposal. Well response, shown in Figure 9, was similar to 1-16. Oil cut increased from 3% to almost 30% and oil rate increased from 1 m^3/d to 3 m^3/d. The increase in oil cut prior to the AWACT treatment is not fully understood, but may be attributed to rate sensitivity associated with a gradual reduction in fluid withdrawal from the well.

Gas Injection Volume

Having proven that AWACT would consistently reduce water production and recover incremental oil, effort was directed towards reducing the stimulation cost by using progressively smaller gas volumes. 1H-9-20-8 W4M and 13F-3-20-8 W4M were treated with 85 10^3 m^3 and 55 10^3 m^3 of natural gas, respectively.

Well 1H-9 was considered depleted prior to the AWACT stimulation. It was a thin well with only 12.8 m of oil pay and poor primary cement quality. Since the well was partially penetrated, it was felt gas stimulation could affect the region below the wellbore and improve performance. As shown in Figure 10, the oil cut increased from 3% to 20%, and to date the well has produced an incremental 1600 m^3 of oil.

13F-3 produced at approximately 10% oil cut for twelve months prior to AWACT stimulation in August 1988. Following treatment, oil cut increased to over 35% and oil production rate tripled to 3 m^3/d. In April 1989, fluid withdrawal was increased from 25 m^3/d to 60 m^3/d, with a corresponding drop in oil cut from 25% to 7%. Response from 13F-3 is shown in Figure 11.

On the basis of these two tests, it was concluded that a small slug was capable of adequately treating a well, and subsequent tests all used small gas volumes in the range of 50 10^3 m^3.

Pattern Flood

During injection at 1L-16, gas production was observed at two offset wells. Since the pool was developed on a uniform seven spot pattern, it was felt that a small slug could be used to treat several wells simultaneously.

A pattern was chosen and 900 10^3 m^3 of gas was injected at the central well, 11J-34-19-8 W4M. To optimize the areal distribution of injected gas, each perimeter well was produced only until the gas production rate reached 3 10^3 m^3/d. Once all

producers experienced breakthrough, injection was terminated and the shut-in wells were returned to production. Gas was produced for a few days, but none of the wells reacted with the typical AWACT response of instant water reduction. Figure 12 shows a composite of the production response from all of the pattern wells and two adjacent wells which experienced gas breakthrough. There was no apparent increase in recovery or production rate.

Gas injection was modelled using a Dykstra-Parsons[14,15] technique. Using lab relative permeability data for the pool, an accurate match of breakthrough time and sweep efficiency was modelled. Based on this analysis, it was concluded that gas fingered through the oil and over time gravity segregated to the top of the reservoir. When the gas finally reached the injectors, it was not positioned to contact the water cone and affect a treatment.

The 11J-34 injector had not produced water prior to the test. Following injection, the oil productivity was cut in half. At the present time, this well has recovered more than 10% of its oil in place, and its oil cut is still above 80%. It would appear that AWACT has had some preventive potential at the cost of a loss in productivity.

Other Reservoirs

To determine whether AWACT would work in other heavy oil reservoirs, three tests were conducted at wells in adjacent reservoirs.

14-1-20-8 W4M produces from a Basal Quartz reservoir and has 12 m of net oil pay over water. The oil has a specific gravity of 0.95 and an estimated live oil viscosity of 50 mPas. Prior to injecting 160 10^3 m^3 of natural gas in May 1988, the well had produced at 16% oil cut for five months. This well tended to slug water, and production measurement had been erratic due to intermittent flow through the bottom hole pump. Following AWACT stimulation, oil cut gradually increased to 20%; however, there was no significant increase in cut as observed at other wells. The data in Figure 13 shows a small gain in recovery, but it is difficult to quantify this with any certainty.

Two other Glauconitic wells, 14-32-19-8 W4M and 3C-5-20-8 W4M, were tested. This reservoir is similar to South Jenner in all respects, except that it has less net oil pay. Well 14-32 has 11 m of oil over water, and 3C-5 has only 6 m.

Well 14-32 produced at an oil cut less than 30% for eleven months preceding AWACT stimulation. Injection of 160 10^3 m^3 of natural gas caused the oil cut to increase to 45%. As with 14-1, it is difficult to use the decline shown in Figure 14 to predict how much incremental oil will result from the treatment.

The cement bond on 3C-5 was poor, and the well produced only 450 m^3 of oil prior to injection of natural gas. Oil cut decreased after injection, and the test was considered unsuccessful.

Chemical Additives

In the early stages of conceptualizing the process mechanisms, two theories were developed. The first was that natural gas caused the reservoir to become strongly water wet. This would inhibit water flow by increasing the irreducible water saturation and reducing the water relative permeability. The second theory acknowledged the oil wet tendency of the reservoir and the natural reduction in water relative permeability when a third phase, gas, is introduced into the flow path. To confirm the theories, field tests were modified to pre-inject a chemical which would alter the reservoir to either strongly water wet or strongly oil wet.

Oil wet tests were conducted at wells 11E and 11I-34-19-8 W4M. These tests, shown in Figures 16 and 17, resulted in the most significant increase in oil rate and oil cut from any of the wells previously tested. Injectivity of gas and chemicals into these wells was extremely low, and one test at 10-16M-20-8 W4M was aborted because neither chemical nor gas could be injected. It is speculated that this is a check valve effect similar to that caused by emulsion blocks[16].

Injection of water wetting chemicals at three wells, 14F-34-19-8, 6M-3-20-8 and 12F-3-20-8 W4M, also resulted in a distinct increase in oil production rate and oil recovery. Unlike the tests using oil wetting chemicals, injectivity was high for all three wells.

These tests of chemical additives did not solve the dilemma of having opposing mechanistic theories; however, it is clear that performance and reliability improved with their use. Research has been initiated using micro-models and core tests to identify the role chemicals play in the AWACT recovery process.

South Jenner Overview

A total of ten wells were cyclically stimulated in the South Jenner field, and the results varied from well to well. To put this in perspective and to account for the variation in performance, the monthly production from these wells was superimposed with time shifted to align the data with the start of AWACT stimulation. This data, plotted in Figure 20, shows an expected incremental recovery of 21,500 m^3 of oil, representing 6% of the original oil in place. On average oil production rate doubled from 20 m^3/d to 40 m^3/d.

NUMERICAL MODELLING

History Match

An existing AWACT well was chosen for a modelling study to optimize gas slug size and to identify the limits of the AWACT process. A successful AWACT well located in the South Jenner

field, 14F-34-19-8 W4M, was chosen primarily because the properties of this well resembled properties of most of the wells chosen for AWACT stimulation. These properties are shown below:

Drainage Area	1	ha
Pay Thickness	19	m
Porosity	23.5	%
Initial Water Saturation	35.3	%
Live Oil Viscosity	97.4	mPas
Dead Oil Viscosity	570	mPas
Solution GOR	22.8	m^3/m^3
Oil Formation Volume Factor	1.055	Rm^3/m^3
Oil Specific Gravity	0.98	
Current Reservoir Pressure	8600	kPa abs
Bubble Point Pressure	8067	kPa abs

A two dimensional radial model was set up with an 11 x 1 x 11 grid system with properties shown below. These grid properties were calculated from open hole logs and build-up test data. Relative permeability curves measured in the laboratory and shown in Figures 2 through 6 were normalized to an initial water saturation of 35.3% and used in a blackoil reservoir simulator with the modified oil wet Stone's Model II.

Grid No	Radius (m)	Grid No	Radius (m)	Grid No	Radius (m)
1	0.33	5	8.4	9	40.4
2	0.96	6	16.4	10	48.4
3	2.12	7	24.4	11	56.4
4	4.30	8	32.4		

Layer	h (m)	ø (%)	Sw (%)	Kr (μm^2)	Kz (μm^2)
1	2.0	20.3	35.3	0.658	0.296
2	3.0	19.4	35.3	0.608	0.273
3	2.0	23.2	35.3	0.393	0.177
4	2.0	24.5	35.3	0.554	0.249
5	2.0	22.5	35.3	0.554	0.249
6	2.0	25.4	35.3	0.708	0.318
7	3.0	26.7	35.3	0.642	0.289
8	3.0	25.9	35.3	0.777	0.350
9	3.0	25.9	90.0	0.364	0.164
10	3.0	25.9	90.0	0.364	0.164
11	18.0	25.9	100.0	0.143	0.064

A good history match of primary production was obtained by reducing the horizontal permeability measured from a build-up test by a factor of 0.4 and setting the vertical permeability to equal 0.45 times the horizontal permeability. This range of absolute permeability and permeability ratio is based on core measurements from adjacent wells.

The model was set up to duplicate the field AWACT test where a natural gas slug of 55 10^3 m^3 was injected in January 1989. Following gas injection, saturation maps were examined. Grid blocks which received a gas saturation value greater than 1% were assumed "stimulated". The lower residual oil saturation and associated relative permeability curves measured in the lab were assigned to "stimulated" grid blocks, and production continued in the model until oil cut reached 4%. Using this method, the AWACT stimulation was matched successfully with no additional modifications necessary. The quality of this match is shown in Figure 21 and is thought to be very good.

Sensitivity to Gas Fingering

Gas fingering, or the channelling of gas, will occur in the reservoir as a direct result of the large difference in mobility between gas and oil. The tendency for channelling will increase when gas is injected at high velocity. To model this phenomenon, the gas relative permeability curve is made more convex upwards, thus increasing gas velocity for a given saturation.

Predictions were made to test the sensitivity of reservoir performance to gas fingering. This work demonstrated that increased fingering results in the movement of injected gas further out into the reservoir to "stimulate" a greater area and improve incremental oil recovery. Because its saturation must exceed a critical value before gas will flow, the greater contact area causes more gas to be trapped, thus reducing the volume of gas which can be recovered on flowback.

The reservoir model for 14F-34 used unaltered lab data for the gas relative permeability. Because the history match accurately predicted both the rate of gas production and the ultimate gas recovery, this is a good test of the quality of history match. These results are shown in Figure 22.

A conclusion drawn from the gas fingering sensitivity is that recovery will be maximized by increasing the contact between gas and oil. This can be done by injecting at high rates and using selective treatments to take advantage of geological information to minimize gas over-ride or under-ride.

Gas Slug Size

The reservoir model was used to estimate the effect of increasing the volume of gas injected. The predictions, shown as a solid line in Figure 23, demonstrate that more gas will yield more oil. Economic analysis will need to be used to evaluate the tradeoff between increased oil and the time and cost of a larger stimulation.

To test the accuracy of this prediction, the performance of the wells in South Jenner which were cyclically stimulated were plotted on Figure 23. The field test data fits the prediction very well except for

two wells, 111-34 and 6M-3. Well 111-34 was part of the pattern test: therefore, the gas volume affecting this well may be understated. The incremental recovery from 6M-3 may be overstated due to the uncertainty in the primary decline. In any case, it is apparent that the incremental oil recovery from AWACT has upside potential.

The gas saturation map shown in Figure 25 represents the condition of the reservoir after injecting an amount of gas equal to 14% of the original oil in place. This map shows that gas distributes itself relatively uniformly over the pay thickness, with the highest gas concentration adjacent to the perforations in the top two layers. A secondary gas saturation peak is also created just below the water-oil contact. This type of behavior was seen at the SHOP combustion pilot observation wells using cased hole neutron logs. Actual gas under-running would be more pronounced if the model distinguished between gas relative permeability in oil and water.

Viscosity Sensitivity

To examine the effect of oil viscosity on recovery, several prediction runs were made using various injected gas volumes and viscosities. The model of well 14F-34 was used with four additional grid blocks in the radial direction to account for a large well spacing of radius 1170 m. The predictions commenced after a water cone was developed and water cut had reached 92%.

Gas volumetric sweep efficiency was calculated as a fraction of a 4 ha oil zone with gas saturation greater than 1%. This information, shown in Figure 25, illustrates that at low viscosity, gas will channel to the top of the reservoir and at medium viscosity, gas will distribute itself relatively uniformly across the pay zone, resulting in the highest sweep efficiency. At high oil viscosity, much of the gas channels at the water oil contact, and sweep efficiency is reduced.

These simulation results imply that AWACT will work better in heavy oil reservoirs providing the viscosity is not too great to prevent gas movement through the oil. The range of applicable viscosity may be influenced by relative permeability and homogeneity of the reservoir.

Remedial Potential

A large gas slug of 500 10^3 m^3 was injected into the enlarged model of well 14F-34 with an oil viscosity of 100 mPas prior to any production. The results indicated that injected gas did not distribute itself over the pay thickness, as it did in the same run with a well developed water cone.

A saturation map , shown in Figure 26, indicates gas channelling both at the top of the reservoir and at the water oil contact. The volumetric sweep efficiency calculated for this case was 12%, as compared to 22% when the well was produced to a high water cut before injecting gas. This result confirms that injected gas will flow more easily in areas with free water saturation due to the mobility difference between oil and water.

This observation has application in understanding the results from the field test of an AWACT pattern flood. Because the gas injection well had a very low water cut, it is possible that the gas channelled to the production wells without contacting much reservoir.

ECONOMICS

The cost of completing an AWACT stimulation depends on gas availability, compression requirements and chemical selection. The most expensive component is compression because most lessors require a minimum three month rental. For this reason it is recommended that several wells be stimulated at the same time to bring the cost per well to approximately $25,000. The following estimates are provided for the reader's convenience.

	Unit	Unit Cost	Typical Job
Chemicals	m^3	$1,000	10
Compressor	month	$16,000	0.25
Natural gas	10^3 m^3	$55	100
Nitrogen	tonne	$1,000	22.5

COMMERCIAL APPLICATION

AEC and Westcoast Petroleum are now using AWACT commercially in the South Jenner field to increase reserves and reduce both the capital and operating cost of handling water. Over the life of the field, it is expected that 120 additional wells will be stimulated to increase recoverable reserves by 300,000 m^3. These reserves will be added at a cost of approximately $3 million or $10/$m^3$. If performance proves to be dependent on gas injection volume, the reserve gain could be 50% greater than expected.

Reserve additions through AWACT treatment are beneficial to corporate depletion rates. This is because the stimulation is conducted as an operating expense and does not influence the capital base.

CONCLUSIONS

1. AWACT, a commercial recovery process, has been proven to increase oil recovery and decrease water production.
2. AWACT works on the basis of creating a trapped gas saturation in the oil to reduce the residual oil

saturation. Three phase relative permeability also contributes to reduced water production.

3. Incremental oil recovery increases with the volume of gas injected. Economic evaluation will determine the tradeoff between incremental oil and the time and cost of additional gas.
4. AWACT should provide better results when the oil viscosity at reservoir conditions is in the range of 30 mPas to 1000 mPas. Geological or reservoir features may influence this range.
5. Wells must have an established water cone or a free water saturation for the injected gas to contact the reservoir efficiently. This will result in maximum incremental oil recovery.

ACKNOWLEDGEMENTS

The authors thank AEC Oil and Gas Company, AOSTRA and Westcoast Petroleum Ltd. for permission to release the information presented in this paper. Our co-workers have also contributed to the success of the AWACT experiments.

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APPENDIX I
MODIFIED STONES LAW II

Water wet relative permeability

$$Kro = Krocw\left\{-(Krwo + Krgo) + \left[\frac{Krow}{Krocw} + Krwo\right] * \left[\frac{Krog}{Krocw} + Krgo\right]\right\}$$

Oil wet relative permeability

$$Krw = Krwro\left\{-(Krow + Krgw) + \left[\frac{Krwo}{Krwro} + Krow\right] * \left[\frac{Krwg}{Krwro} + Krgw\right]\right\}$$

where: Kro = 3 phase oil relative permeability
Krw = 3 phase water relative permeability

Krocw = Kro at connate water
Krwro = Krw at residual oil

Krow = Kro from a water-oil displacement test
Krwo = Krw from a water-oil displacement test

Krog = Kro from a gas-oil displacement test
Krgo = Krg from a gas-oil displacement test

Krwg = Krw from a gas-water displacement test
Krgw = Krg from a gas-water displacement test

Figure 1
OIL WET 3 PHASE RELATIVE PERMEABILITY
Calculated Using Modified Stone II

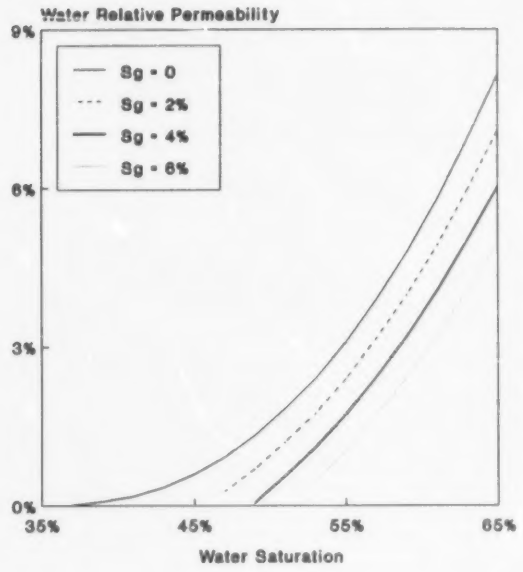


Figure 2
AWACT IN THE OIL AND WATER REGIONS

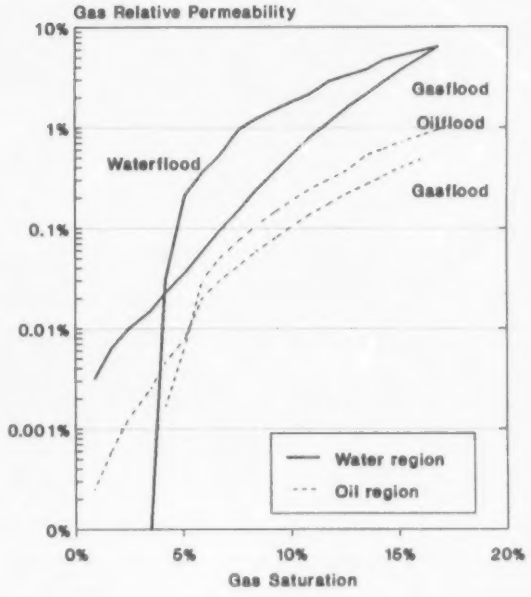


Figure 3
OIL RELATIVE PERMEABILITY COMPARISON

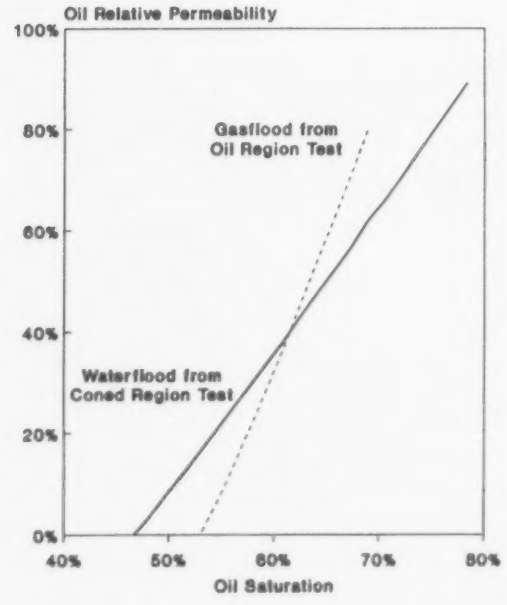
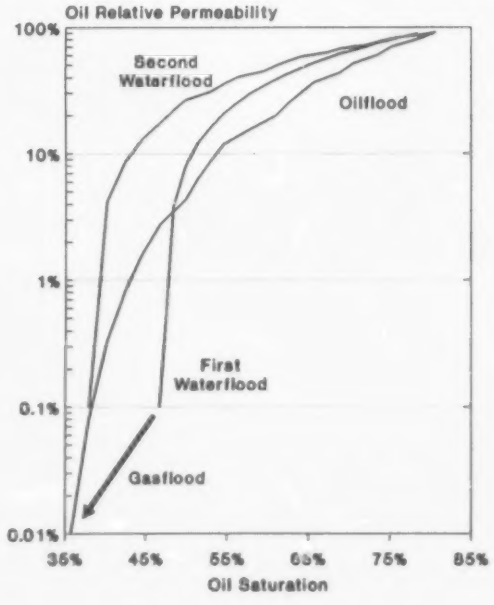


Figure 4
AWACT IN THE WATER CONED REGION



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AWACT IN THE WATER CONED REGION

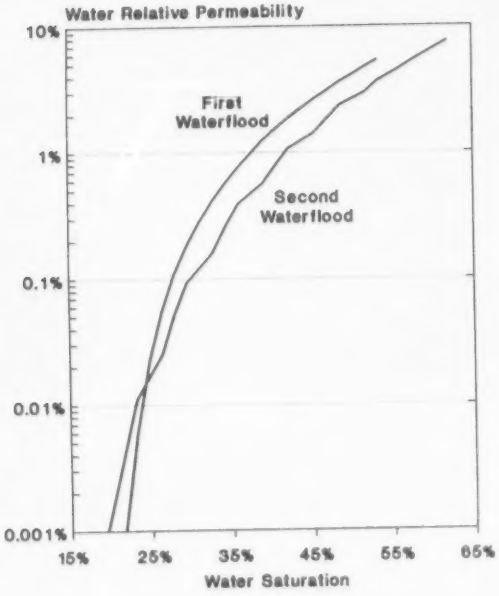


Figure 6
AWACT IN THE WATER REGION

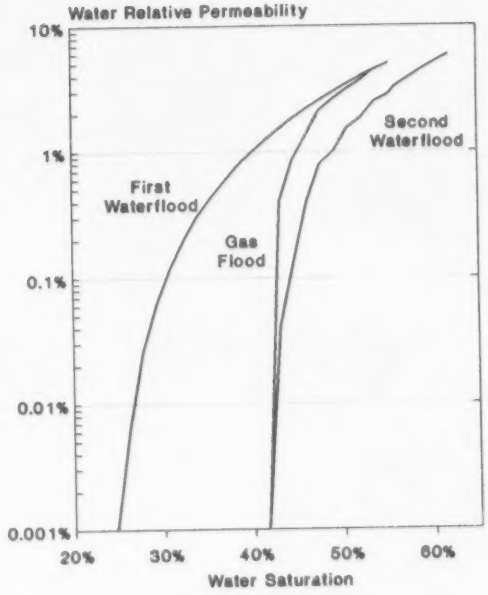


Figure 7
ORIGINAL AWACT TEST AT 1-16-20-8

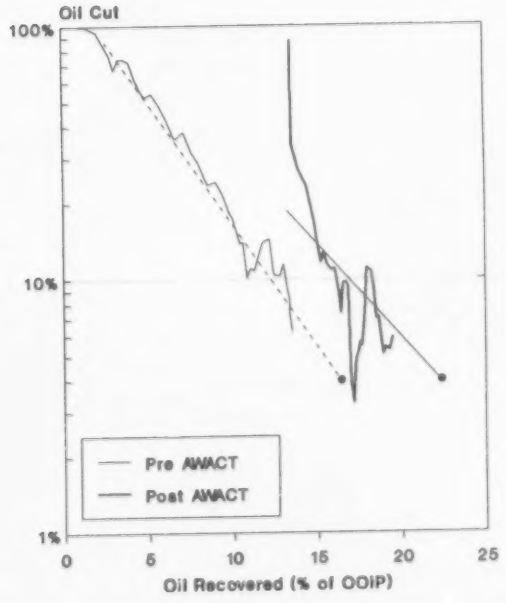


Figure 8
MULTI CYCLE AT 4-10-20-8

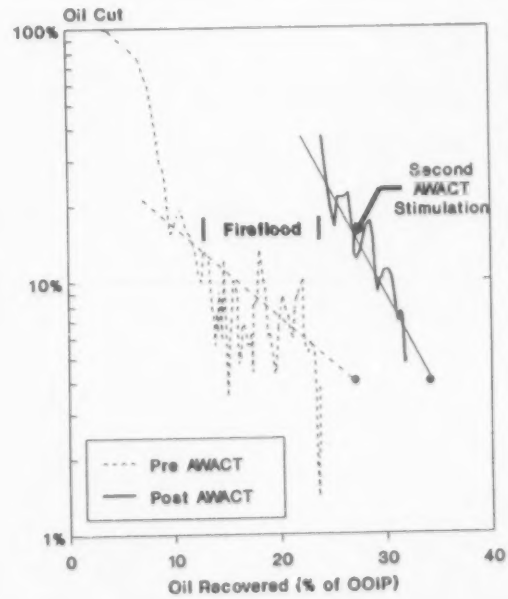


Figure 9
TEST OF REPEATABILITY AT 3-3-20-8

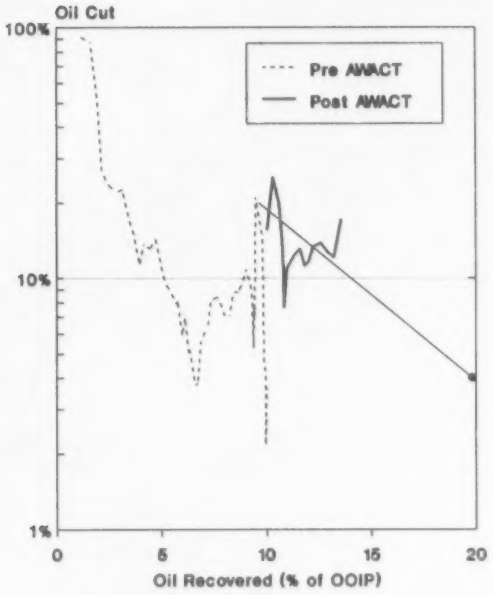


Figure 10
SMALL GAS SLUG AT 1H-9-20-8

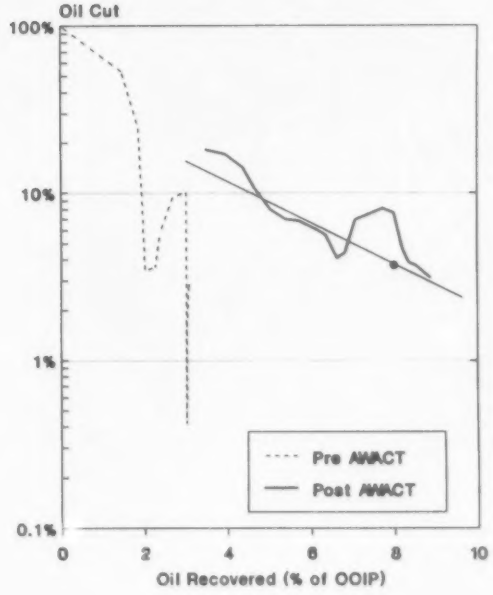


Figure 11
SMALL GAS SLUG AT 13F-3-20-8

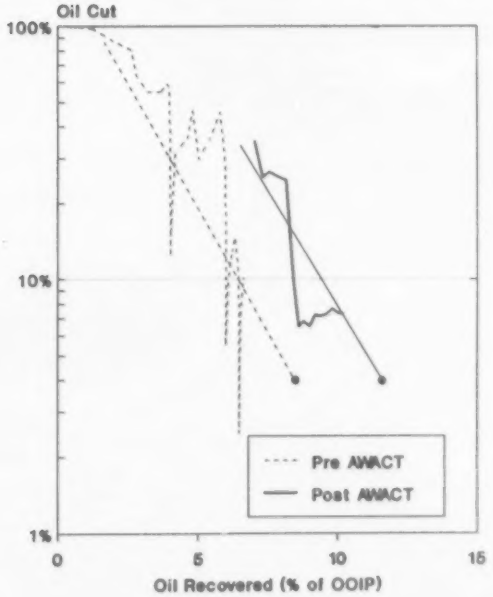


Figure 12
SEVEN SPOT PATTERN INJECTION

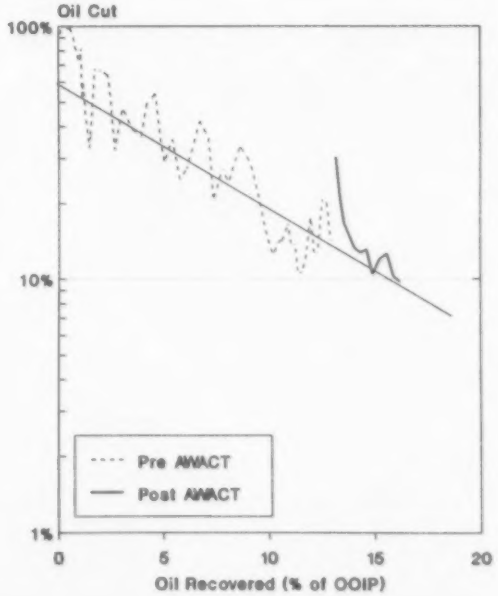


Figure 13
BASAL QUARTZ TEST AT 14-1-20-8

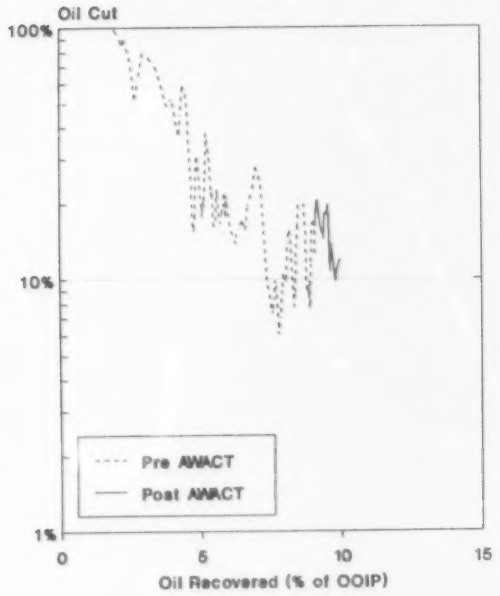


Figure 14
GLAUCONITE TEST AT 14-32-19-8

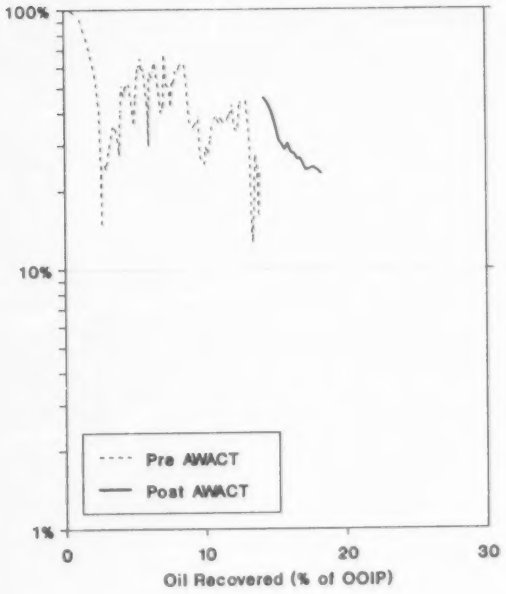


Figure 15
OIL WET CHEMICAL AT 11E-34-19-8

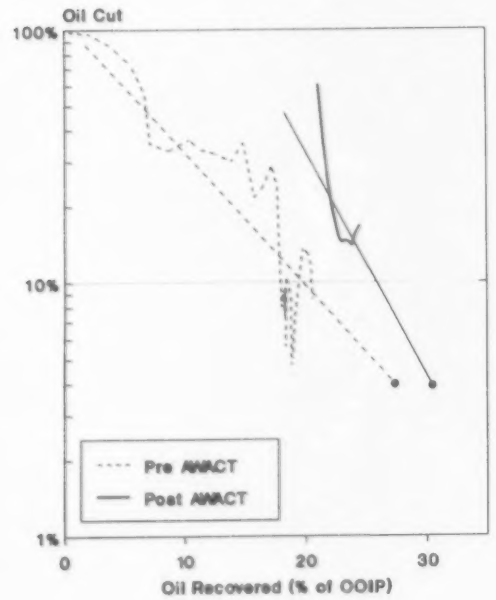


Figure 16
OIL WET CHEMICAL AT 11I-34-19-8

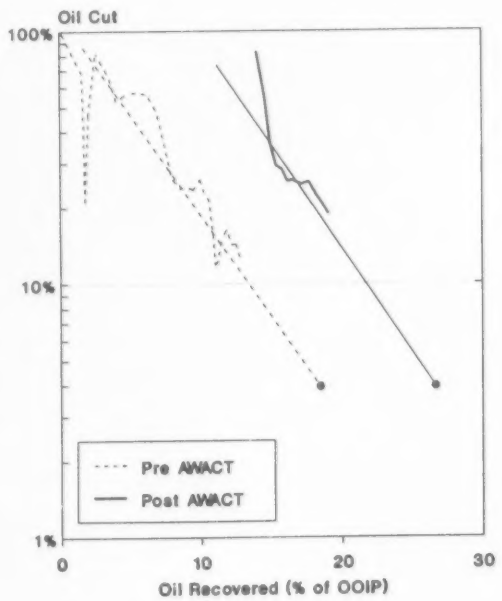


Figure 17
WATER WET CHEMICAL AT 14F-34-19-8

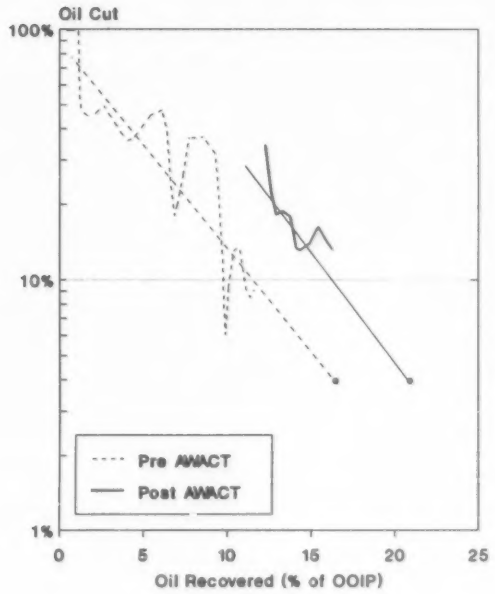


Figure 18
WATER WET CHEMICAL AT 6M-3-20-8

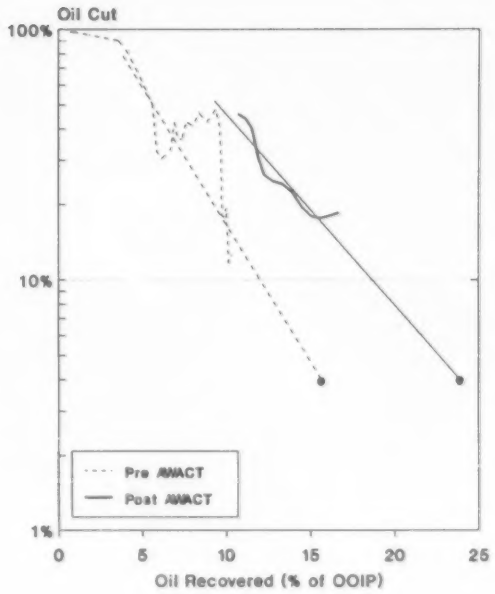


Figure 19
WATER WET CHEMICAL AT 12F-3-20-8

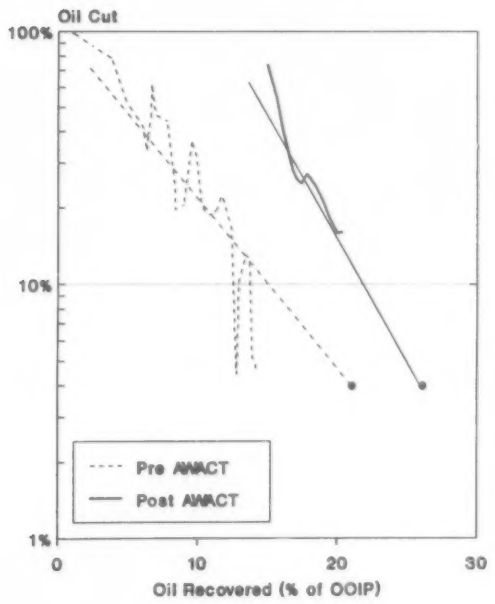


Figure 20
TEN SOUTH JENNER AWACT TESTS

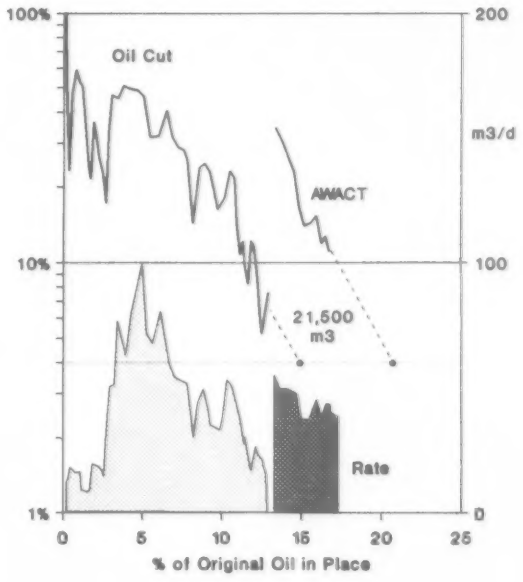


Figure 21
AWACT RESERVOIR SIMULATION
14F-34-19-8

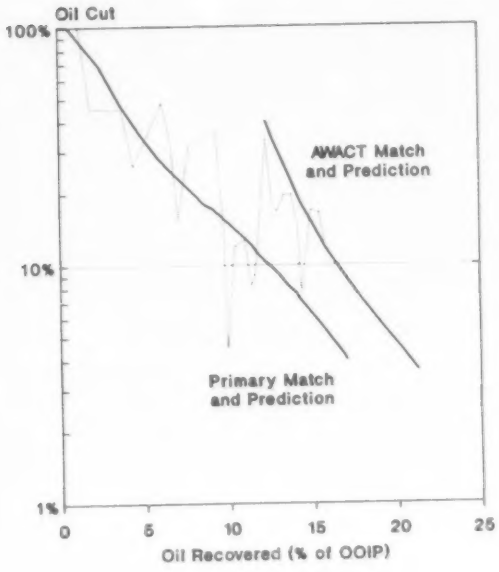


Figure 22
GAS PRODUCTION HISTORY MATCH
14F-34-19-8

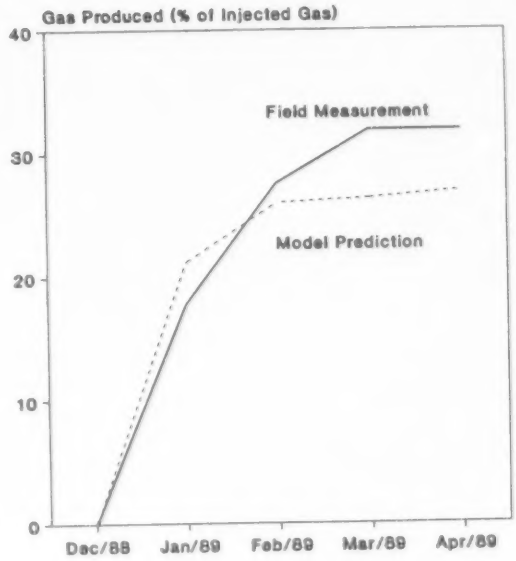


Figure 23
AWACT RECOVERY PREDICTION

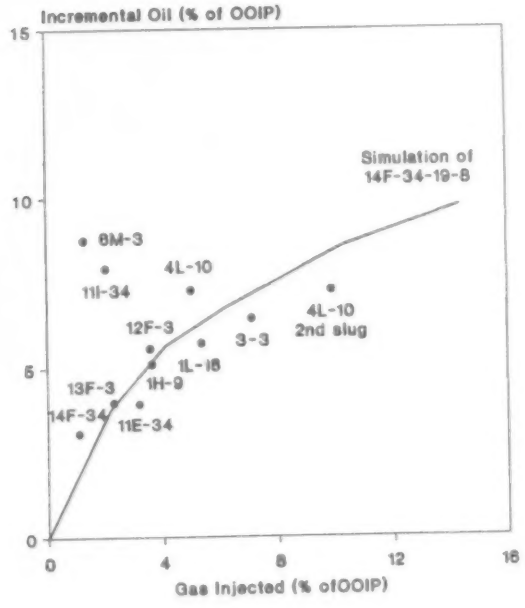


Figure 24
AWACT PERFORMANCE
SENSITIVITY TO OIL VISCOSITY

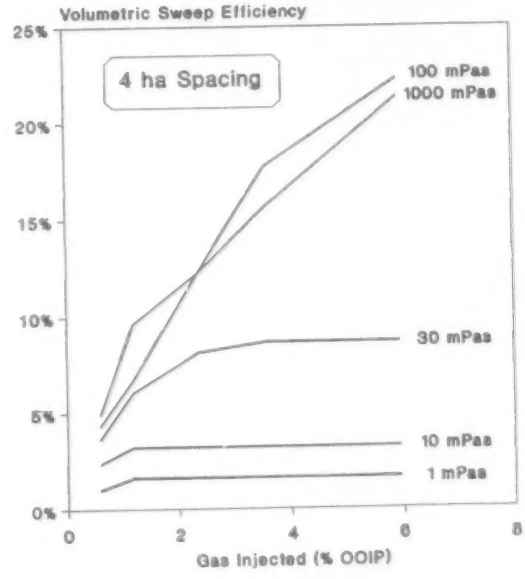


Figure 25

14F-34 AT 90% WATER CUT

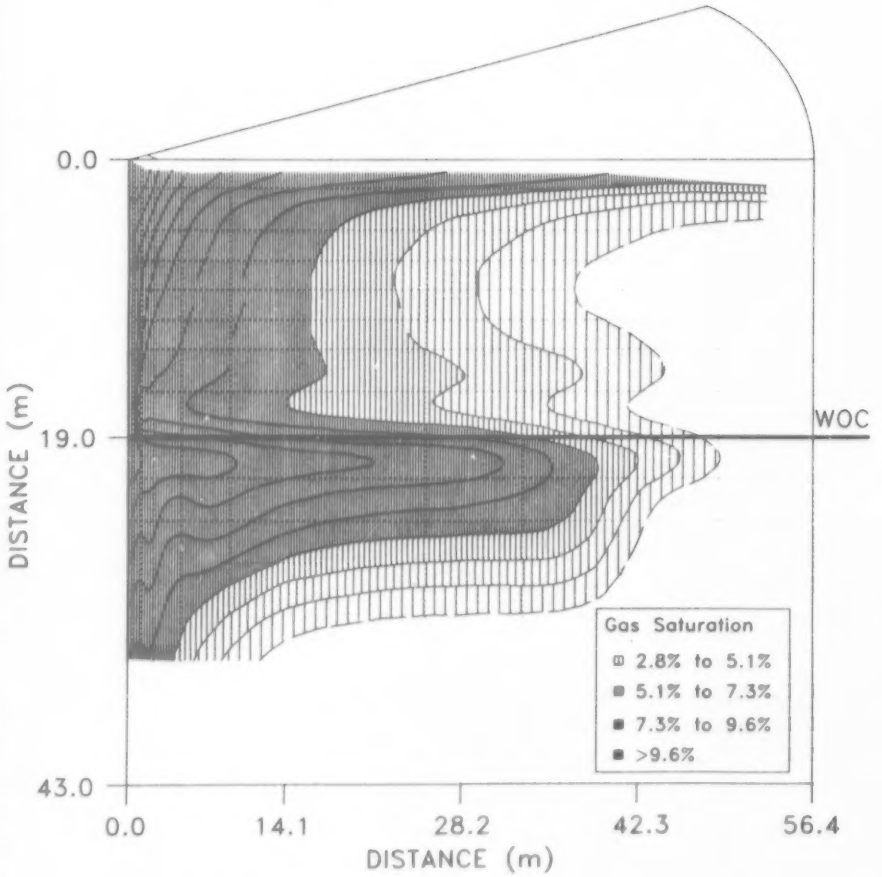
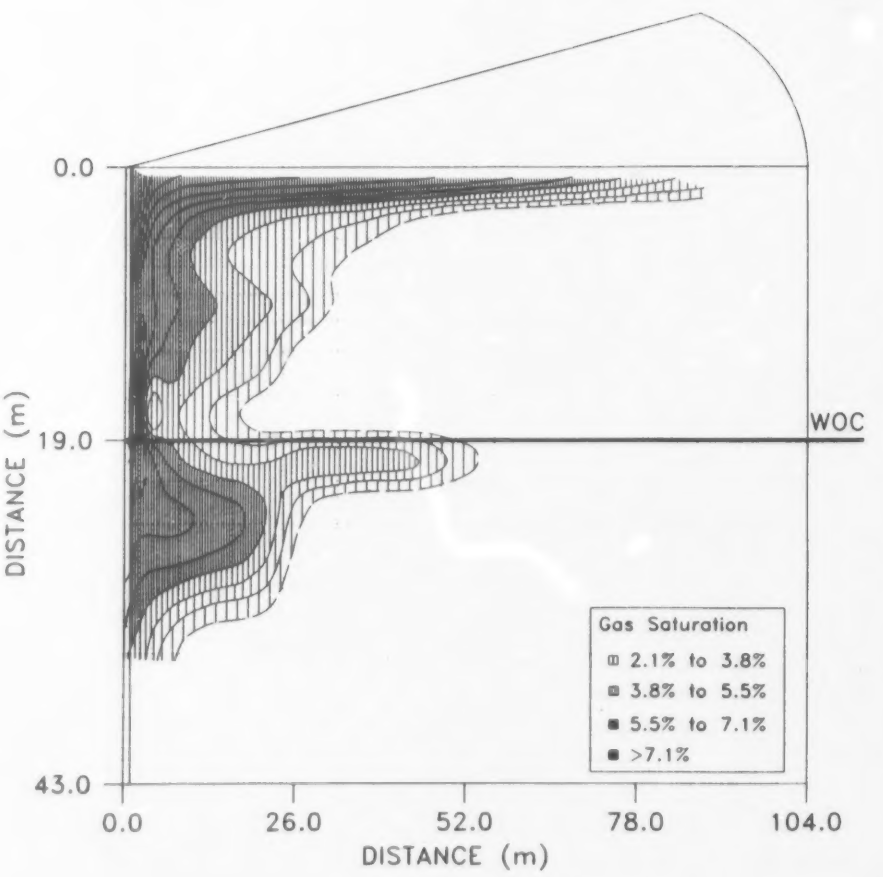


Figure 26

14F-34 AT 0% WATER CUT



CO_2: Potential For EOR

S.M. Farouq Ali, University of Alberta, Edmonton, and S.B. Dyer, Saskatchewan Research Council, Regina.

Abstract. The immiscible carbon dioxide flooding process - to distinguish it from the miscible version, offers potential for the recovery of moderately viscous heavy oils (100-2000 mPa.s). It is not a substitute for steam injection, but it may offer an alternative for reservoirs that are not suitable for thermal recovery, e.g. thin formations. The immiscible carbon dioxide process utilizes carbon dioxide in the gas phase, with alternate water injection. The process has been studied in scaled model experiments, providing insight into the principal mechanisms. This paper considers the effect of carbon dioxide on rock and fluid properties, and provides a summary of field experience.

INTRODUCTION

On a worldwide basis, there is enough conventional oil to last for over 40 years, but less than one percent of it is in Canada. This is shown in Fig. 1, where the total area represents the oil reserves of the world, and each square is equivalent to one year's oil consumption of the world. On the other hand, Canada has vast heavy oil and oil sands resources, totalling nearly 500 billion m^3, which is roughly equal to the conventional oil-in-place worldwide, applying a recovery factor of 33% to the reserves shown in Fig. 1. This is evident from Fig. 2, which shows in-place conventional oil, heavy oil and other resources. It is clear that Canada's energy needs will have to be met through the exploitation of the heavy oil and oil sands.

A considerable amount of heavy oil in Canada - nearly one-half - occurs under reservoir conditions that are ill-suited for the application of thermal methods, such as steam injection. This is the case when the formations are thin (<10 m), too deep (>1000 m), permeability is not high enough to permit satisfactory injection rates, and possibly the oil saturation is low. A non-thermal recovery method is needed for such conditions. One method that offers promise is the immiscible carbon dioxide flooding process. It is believed that over three billion m^3 of heavy oil in Alberta and Saskatchewan are amenable to this recovery method. Here 'immiscible' means that carbon dioxide is injected at subcritical pressures, to distinguish the process from the miscible version. We shall discuss the dominant effects of carbon dioxide on a typical heavy oil, and examine field results. Criteria will be offered for process selection.

OIL DISPLACEMENT PROCESSES USING CARBON DIOXIDE

Several versions of the immiscible carbon dioxide flooding process have been proposed. These are illustrated in Fig. 3, and can be outlined as follows:

Carbonated waterflooding process. Carbonated waterflooding was proposed in the fifties under the name 'ORCO' process (1), as illustrated in Fig. 3(a). The dissolved carbon dioxide diffuses to the front, lowering the oil viscosity, but the diffusion rate is very slow, and a substantial improvement in the mobility ratio is unlikely. Holm (2) compared carbonated water and a single carbon dioxide slug on a 5 mPa.s oil. The slug recovered 30% more oil than carbonated water. The ORCO process was originally intended to provide a solution gas drive effect for the Bradford crude oil (4 mPa.s).

Continuous carbon dioxide injection. In this instance, carbon dioxide is injected continuously until a maximum gas-oil ratio is reached, as determined by practical considerations. In heavy oil-carbon dioxide systems, the process is severely restricted by the lack of mobility and gravity control. According to Rojas (3) carbon dioxide requirement (defined as the volume of carbon dioxide needed per unit volume of the oil recovered) is up to 10 times that for the WAG process, described below. Sayegh and Maini (4) found that the recovery of a 23700 mPa.s Lloydminster oil was as low as 3% upon carbon dioxide breakthrough. Garcia (5) reported a successful continuous carbon dioxide pilot in the Oveja field, in Venezuela, indicating that the process is likely to work well in a thick formation, with good gravity segregation.

Single carbon dioxide slug followed by water. This process is illustrated in Fig. 3(b), and is a definite improvement on the previously described processes. Here a single slug of carbon dioxide gas is driven by water. There is still no mobility control at the flood front, and oil recovery is likely to be low due to instabilities. Rojas and Farouq Ali (6) noticed early carbon dioxide breakthrough, as well as an overall rate dependence.

Simultaneous Carbon Dioxide and Water Injection. Figure 3(c) illustrates simultaneous carbon dioxide and water injection. There are a number of practical problems associated with this process, such as cost of dual completions, corrosion, and reduced injectivity due to two-phase flow. However, in theory the process works well, as shown by Warner (6), on the basis of numerical simulations.

Water-Alternating Gas (WAG) Process. Figure 3(d) illustrates the immiscible carbon dioxide WAG process. In this case, slugs of carbon dioxide and water are alternately injected until the desired volume has been injected. The last carbon dioxide slug is followed by a waterflood to recover any remaining mobile oil. The water-alternating gas ratio is defined as the ratio of the volume of water to that of carbon dioxide at reservoir conditions. In this process, alternate water injection provides mobility control as well as improved mixing of water and carbon dioxide. Several investigators, notably Rojas and Farouq Ali (6,8,9), have conducted detailed studies of the process. Warner's (7) simulation results showed that the WAG process did not recover as much oil as simultaneous injection. Also, notice that Huang and Holm (10) found that in the case of a *miscible* carbon dioxide flood, more oil was trapped in the WAG rather than in the simultaneous injection mode. Nevertheless, the WAG process is practical, while simultaneous injection is not.

We shall next discuss the various effects of carbon dioxide on oil, and how they may contribute to oil recovery.

HOW CARBON DIOXIDE MIXES WITH HEAVY OIL AND RESERVOIR WATER

Carbon dioxide mixes with the reservoir fluids, viz. oil and water, by three mass transfer mechanisms: solubility, diffusion and dispersion, of which solubility is the most important.

Solubility in oil. Solubility of one substance in another depends fundamentally upon the ease with which the two molecular species are able to mix (6). Klins (11) stated that for low pressure application (<7 MPa), the major effect would be the solubility of carbon dioxide in crude oil. The solubility of pure carbon dioxide in Lloydminster Aberfeldy (15-17°API) oil at 5.5 MPa and 20.6°C is approximately 70 sm^3/sm^3 of oil. Solubility is a strong function of pressure, and to a lesser degree, temperature and oil composition. Solubility increases with pressure and decreases with temperature and reduced API gravity.

Simon and Graue (12) carried out one of the earliest studies on carbon dioxide solubility in several oils. Carbon dioxide is more soluble in hydrocarbons as a gas rather than a liquid phase.(2,14). Miller and Jones(13), and Briggs and Puttagunta (14), showed that a sharp break occurred in the P-V-T curves at the carbon dioxide condensation pressure. At this point carbon dioxide changes from a gas to a liquid phase. Further increases in pressure beyond this point (~6.9 MPa & 24°C) resulted in only small amounts of carbon dioxide liquid dissolving in the crude oil.

Effect of a gas on solubility. In 1926, Beecher and Parkhurst (15) found that carbon dioxide was more soluble, on a molar basis, in a 30.2°API oil than air and natural gas (CH_4). Work by Patton *et al.*(16), and later by Holm and Josendal (17), showed that carbon dioxide solubility was reduced with increased concentrations of nitrogen and methane. Saxon *et al.* (18) found that carbon dioxide solubility decreased as the natural bubble point pressure of crude oil increased, requiring higher carbon dioxide injection pressures. The reduction in solubility due to methane gas was also confirmed by Sayegh and Maini (4), when simulating methane impurities in recycled carbon dioxide gas for the "huff-n-puff" process.

Contrary to the findings of Saxon *et al* and Sayegh and Maini, Chung and Burchfield (19) theorized that the solubility of carbon dioxide, in crude oils at reservoir conditions, would gradually increase as more carbon dioxide is injected. They felt that the carbon dioxide would strip the solution gas from the crude causing the methane to be released.

Solubility in water. Carbon dioxide is soluble in water to a much lesser extent than in crude oils. The solubility of carbon dioxide in water is a function of salinity, pressure, and temperature. Data presented by Dodds *et al.* (20) show that in the temperature range of 20-70°C and for pressures below 10 MPa, the solubility of carbon dioxide, in fresh water, is less than six percent by weight.

Diffusion. Carbon dioxide mixes with oil by diffusion as well as by solution. Diffusion is the macroscopic transport of mass, due to random molecular motion, and is independent of any convection within the system (3). Molecular diffusion is responsible for mass transfer at the pore level, and has been shown to be an important rate controlling mechanism in carbon dioxide floods (21). Diffusion helps carbon dioxide penetrate into heavy oil which may help to reduce gravitational and viscous instabilities.

Several researchers (22,23) have conducted experiments to determine diffusion coefficients of carbon dioxide in hydrocarbons at atmospheric conditions. The carbon dioxide diffusivity coefficients for Lloydminster Aberfeldy oils are in the range of 2.56×10^{-5} to 3.59×10^{-5} cm^2/s. Rojas and Farouq Ali (9) concluded that while the diffusion of carbon dioxide in heavy oils is high, it represented less than 20 percent of that obtained by solution under the same subcritical conditions.

Literature data (23,24) indicate that the diffusion rate of carbon dioxide in water is greater than the diffusion rate of carbon dioxide in oil. Denoyelle and Bardon (24) found that the diffusion of carbon dioxide in a liquid (oil and water) proceeded at an intermediate rate between that in water alone or in oil alone. They also pointed out that the porous medium had a negligible effect on molecular diffusion due to the pore scale being so much larger than the molecular scale.

Dispersion. Additional mixing of fluid occurs in the porous medium due to velocity. This additional mixing is due to the dispersive force of attraction which occurs in highly polarizable molecules such as hydrocarbons. For the moderate velocities encountered at reservoir conditions, however, transport of carbon dioxide by convective dispersion is largely surpassed by molecular diffusion and solution.

HOW CARBON DIOXIDE AFFECTS OIL, WATER, ROCK PROPERTIES

Viscosity. The most important effect of carbon dioxide on crude oil systems is the large reduction in oil viscosity. Five to thirty fold reductions in viscosity at carbon dioxide saturation pressures have been reported (1,25). The viscosity of oil saturated with carbon dioxide is a function of temperature, pressure, and concentration of dissolved carbon dioxide.

A number of researchers (6,26-28) have found that greater percentage reductions in viscosity occur at lower operating temperatures. Kilfeareiter (29) noted that above 145°C, the effect of dissolved carbon dioxide on oil viscosity was negligible. Research by Rojas and Farouq Ali (6), and others indicated that the higher the initial oil viscosity, the greater the percentage reduction in viscosity when saturated with subcritical carbon dioxide. Rojas and Farouq Ali reported a 95.6 percentile decrease in viscosity for a 1080 mPa·s oil and a 98.3 percentile decrease in viscosity for a 4900 mPa·s oil, both saturated with subcritical carbon dioxide at 5.5 MPa and 21°C. They also noted that these reductions in viscosity, by carbon dioxide saturation, were similar to heating the oil samples to approximately 90°C.

Equilibrium time. Another factor which influences heavy oil-carbon dioxide viscosity, is the equilibrium time, after which there is no change in viscosity with time. Experiments conducted by Goss and Exall (30) showed that an 18000 mPa·s sample of bitumen, exposed to a 6.8 MPa carbon dioxide pressure at 50°C, required 12.5 days to reach equilibrium. The final viscosity was 8000 mPa·s, a 55.6 percentile decrease. Scott (31) analyzed laboratory data of a Lloydminster crude oil, noting that as the carbonation pressure was decreased and carbon dioxide liberation occurred, the viscosity reduction was retained even at relatively low pressures.

Water viscosity. Due to the relatively low solubility, the viscosity of formation water is assumed to be independent of carbon dioxide saturation. Tumasyan et al. (32) found that the viscosity of water slightly increased when fully saturated with carbon dioxide. They found that the viscosity of formation water increased from 0.562 to 0.650 mPa·s when saturated with carbon dioxide at 6.9 MPa and 52°C, an increase of 15.6%.

Swelling. Crude oils swell when contacted with carbon dioxide. The amount of swelling increases with increased carbon dioxide solubility. Briggs and Puttagunta (14) presented swelling factors for Aberfeldy Crude oil in the presence of carbon dioxide at 20.6°C. Swelling factors increase sharply at pressures below the carbon dioxide bubble point pressure. The rapid increase in swelling factor, with increasing carbon dioxide injection, at pressures above 6 MPa is due to the formation of a liquid layer of carbon dioxide floating on top of the oil.

Holm and Josendal (17) indicated that there is some expansion of water (2-7%) when carbon dioxide goes into solution. Mungan (33) suggested that because the carbon dioxide solubility was much lower in water relative to oil, the water expansion would be less than 1 percent and therefore the change would be insignificant and may be ignored.

Figure 4 is a composite plot of swelling factors, solubility, and viscosity of carbon dioxide in the Aberfeldy oil at 20.6°C. All of the data for this figure was taken from Reference 1.

Oil density. Holm and Josendal (17) also noted that carbon dioxide has a surprising effect on the density of crude oil. Opposite to what one may expect, the density of crude oil increased as it became saturated with carbon dioxide. Miller and Jones (13) also found that Wilmington (17°API) oil density increased with increasing carbonation pressure.

Water density. Parkinson and de Nevers (34) presented limited data on water density measurements of carbon dioxide saturated solutions at pressures up to 3.4 MPa. Analysis of this data shows that the density of carbon dioxide-water systems, in equilibrium, is a weak linear function of pressure at constant temperature.

Interfacial tension. Beecher and Parkhurst (15) conducted experiments in 1929 to determine the interfacial tension between crude oils and gases. Their results indicated a reduction of approximately 20% in the surface tension of crude oils in the presence of carbon dioxide. Breston and Mcfarlane (35) showed that the interfacial tension between Bradford crude and water can be reduced from 28.8 to 18.1 mN/m by carbonation at 5.2 MPa. Interfacial tension investigations by Scott *et al.* (36) and Farouq Ali *et al.* (37), showed that any change in pH from neutral (pH=7), decreased the interfacial tension.

Rojas and Farouq Ali (6) found that interfacial tension decreased moderately with increasing carbonation pressure of brine. The interfacial tension was reduced from approximately 25 to 16 mN/m when the pressure was increased from 0.1 to 5.5 MPa (see Figure 5). They indicated that the reduction in interfacial tension may be due to the action of carbonic acid on the nitrogen bases, found in the Aberfeldy crude oil. The formation of surfactants would then concentrate at the oil-water interface. Martin (38) postulated that the carbon dioxide chemically bonded with the nitrogen bases to form polar compounds, which would drastically reduce the interfacial tension of oil-water systems.

The reduction in interfacial tension, due to concentrated surfactants at the oil-water interface, may promote the in-situ formation of water-in-oil emulsions. Rojas and Farouq Ali (6) describe the mechanisms of in situ emulsification, during immiscible displacement of heavy oil by carbon dioxide, as follows:

1. Fingers of formation water in the swollen carbonated oil lead to the formation of large brine droplets inside the oil.
2. The reduction in interfacial tension between the oil and the acidic brine breaks down the droplets into small, more stable brine droplets.

Asphaltene precipitation. Multiple liquid phases may exist in equilibrium when carbon dioxide and crude oil mix. In some cases a solid phase may appear. Deposition of asphaltene precipitates can cause serious problems in the reservoir, such as constriction of fluid flow passages or injectivity problems associated with wettability reversal (39). Asphaltene precipitation occurs when the hydrocarbons and polar fractions lose their ability to disperse colloidally the asphaltene fraction.

Factors which influence asphaltene flocculation are: crude oil composition, pressure, temperature, and properties of asphaltenes. Several investigators have examined asphaltene precipitation in light oils, when using carbon dioxide for achieving multi-contact miscibility.

Fuhr *et al.* (40) studied the effects of carbon dioxide on asphaltene flocculation in a Lloydminster heavy oil. Experiments showed that an increase in carbon dioxide pressure increased the tendency for asphaltenes to flocculate from toluene solutions in heavy oil. Onset of asphaltene flocculation occurred at higher pressures as the toluene-to-oil ratio decreased. Also, asphaltene precipitation decreased with an increase in temperature, viz. carbon dioxide solubility decreased. For the Lloydminster heavy oil sample, asphaltenes began to precipitate at carbonation pressures greater than about 3.5 MPa without the addition of heptane.

Reaction with carbonates. Many formations contain carbonates in some form. Carbonates constitute the bulk matrix in limestone and dolomite reservoirs. In sandstone reservoirs, carbonates are often found as cements consolidating the sand grains. The carbonates most commonly found in reservoir rocks are those of calcium and magnesium.

Carbonated water, formed when injecting carbon dioxide and water into a well, will react with the carbonate minerals in the reservoir. Ellis (41) summarized the chemical process as follows:

1. Carbon dioxide and water are injected into the reservoir and the carbon dioxide dissolves in the water forming hydrogen carbonate, which then dissociates to give carbonic acid.

$$CO_{2_g} \Leftrightarrow CO_{2_{aq}} + H_2O \Leftrightarrow H_2CO_{3_{aq}} \Leftrightarrow H^+_{aq} + HCO^-_{3_{aq}}$$

2. The acid then reacts with the carbonate, such as calcite

$$H^+_{aq} + HCO^-_3 + CaCO_{3_s} \Leftrightarrow Ca^{2+}_{aq} + 2\left(HCO^-_3\right)_{aq}$$

The factors that affect the equilibrium of the above equations are: changes in the concentrations of reactants and products, pressure, and temperature.

Effect on permeability and porosity. Lund and Fogler (42) suggested that the dissolution occurred at preferred sites such as exposed grains and constrictions. On the contrary, Ross *et al.* (49) felt that the phenomenon of channeling was more likely to be the dominating mechanism leading to increased permeability. They showed that a North Sea sandstone core increased in permeability from 60 to 770 md when flooded with carbonated water at 6.9 MPa and 20°C. They also noted that porosity was not significantly altered. Kiins (11) suggested that carbonic acid may also stabilize clays, reducing swelling and plugging, due to the reduction in pH. Several investigators (6,43,44) have also noted the negative effects of rock dissolution. They found that small particles and/or carbonate precipitates could block pore channels, thus reducing permeability.

IMMISCIBLE CARBON DIOXIDE FIELD PROJECTS

Historical note. Pilot testing of the immiscible carbon dioxide process began as early as 1949 in New York State by the Bradely Producing Corporation. The first tests utilized carbonated water injection. The results were discouraging but several important features of the process were discovered (45), viz. injectivity increased, there were no corrosion problems, and additional oil was recovered.

The first full scale ORCO flood, which essentially involved carbonated water injection, was conducted by the Oil Recovery Corporation in 1958 in Bartlesville, Oklahoma. The ORCO flood was marginally successful but not economically feasible due to the tremendous cost of transporting and processing the carbon dioxide.

The first injection of gaseous carbon dioxide was conducted in the Ritchie field of southern Arkansas in 1969. This process had previously been patented by P.C. Keith (an associate of U.S. Oil and Refinery Company) (45), and was considered a localized stimulation process or cyclic single-well ('huff-n-puff') stimulation.

Approximately eighty other immiscible carbon dioxide projects have been reported in the literature (46-48). The majority of the projects employed the localized stimulation, viz. cyclic single-well operation, while some others used the more conventional flooding patterns utilizing the water-alternating-gas (WAG) process.

Reservoir characteristics. Reservoir characteristics and fluid properties vary widely among the field tests reported. Table 1 presents the formation and fluid properties for all of the immiscible carbon dioxide projects found in the literature. Detailed data in the tables were taken from Pande (46), which is an excellent source of information on most of the immiscible as well as miscible projects reported throughout the world.

The vast majority of field tests have been carried out in sandstone lithologies, with a few tests conducted in dolomite or limestone formations. Depths vary from 183 to 3962m with the majority in the 1500 to 2000m range, with formation thicknesses of 10m or less; several were in the range of 30 to 64m. There is no correlation of the depth/thickness ratio. Porosities vary from 2 to 37% with the majority in the 25 to 30% range. Permeability variation among the fields is extremely large and no particular range of optimal permeability is apparent. Reservoir temperatures for the most part fall in the range of 45 to 70°C while initial reservoir pressures vary from 7 to 27 MPa with the majority in the range of 8 to 17 MPa.

Fluid properties. Fluid properties are slightly more consistent than the formation characteristics. The majority of hydrocarbons exploited by the immiscible carbon dioxide displacement process are in the range of 10 to 25°API with viscosities varying widely. Note that the Amoco project at Gregoire Lake had a crude oil viscosity greater than 100,000 mPa·s at 10°C. Amoco planned to inject steam and carbon dioxide in this project. Most fields, after undergoing primary production, began with an oil saturation between 30 and 60% of the initial oil in place (IOIP) before the immiscible carbon dioxide process was initiated.

Secondary vs. tertiary. Both secondary and tertiary recovery methods have been used in the field tests and have performed satisfactorily. Almost all the fields had previously undergone primary production resulting in recoveries ranging from 20 to 30% IOIP. Operating pressures varied from 1.2 to 2.8 times the reservoir pressure at start of carbon dioxide injection in the hope of obtaining near miscible conditions.

Carbon dioxide cyclic stimulation. The majority of projects, at least initially, began with the stimulation or cyclic single-well process. This was to re-pressurize the reservoir in the vicinity of the well and take advantage of the solubility of carbon dioxide in oil at elevated pressures. In some cases, a soak period was instituted to increase the contact time between the carbon dioxide and the oil. This process is analogous to the 'huff-n-puff' technique used in many thermal operations.

Patton *et al.* (10) reported key operating parameters for a profitable cyclic single-well carbon dioxide stimulation, viz. carbon dioxide slug size, back pressure during production, and the number of cycles.

In most cases reported (16,46) the effectiveness of carbon dioxide decreased in subsequent cycles. Two to three cycles appears to be the optimum in reported field tests. Claridge (49) suggested that cyclic carbon dioxide stimulation has a narrower range of application than full scale carbon dioxide flooding. Carbon dioxide cyclic stimulation was reported to be more successful in reservoirs where inter-well communication was poor. In reservoirs with good inter-well communication, a full scale carbon dioxide flood is favoured over the very localized cyclic single-well stimulation process. The single-well process is reported to be very successful for light oil reservoirs, with viscosities less than 30 mPa·s, but has not been successful in unconsolidated heavy oil reservoirs (40).

The cyclic carbon dioxide well stimulation process has inherent shortcomings: during the injection phase, the high injection rate would favour carbon dioxide segregation as much as its dissolution in a heavy oil in view of slow mass transfer. When the well is put back on production, the dissolved carbon dioxide will come out of solution, rendering the oil more viscous. The overall process is much less effective than cyclic steam stimulation.

WAG immiscible carbon dioxide floods. The water-alternating-gas (WAG) process has also been tested in the field and has shown improved recoveries over the continuous injection process and the ORCO process (50). The WAG process looks promising for heavy oil reservoirs. This is due to the improved mobility control resulting in a more efficient displacement and lower carbon dioxide requirements (46). Injection of a continuous slug of carbon dioxide was tested in a few fields and found to be inefficient and uneconomical (45). Massive processing facilities are needed to make this type of project economical.

Key process indicators. Several indicators are used to predict the performance and economic aspects of an immiscible carbon dioxide flood. Performance indicators such as initial increase in oil production and incremental oil recovery, due to carbon dioxide injection, show the operator if a field is responding to a particular enhanced oil recovery (EOR) technique favourably. Factors such as carbon dioxide requirement, carbon dioxide retention, cost, transportation and processing, are the key economic indicators.

The initial response due to carbon dioxide flooding is similar to that encountered in steamfloods (6,51). Extensive data was not reported in this area but some reports (46) have shown initial oil production rates increasing from 65 to 2700% with an accompanying decrease in water production rate varying from 4.5 to 730%. These drastic changes in the respective production rates are somewhat shortlived. Production reverts to marginal increases depending on the cycle and soak times in the stimulation processes, and on the WAG ratios in flood pattern projects. Incremental oil recoveries have been projected to range from 0.04 to 17% IOIP. Carbon dioxide requirement projections varied from 35 to 2900 sm^3/sm^3 with the majority in the range of 500 to 1000 sm^3/sm^3. Retentions generally were in the range of 65 to 80% of that injected.

Operational problems. A variety of operational problems have been reported in the literature. The greatest concern to most operators was securing a viable source of carbon dioxide. The earliest sources of carbon dioxide came from dry ice, solid carbon dioxide, which was transported to the injection site for carbonated waterfloods. More recently, several large pipelines have been constructed in the United States to supply the necessary volumes of carbon dioxide for such large scale projects. In several cases the processing of stack gas from a nearby refinery was implemented.

Corrosion problems, due to the formation of carbonic acid, have been minimized by utilizing some or all of the following procedures (51,52):production well flow lines constructed of fibreglass, injection well tubing string internally coated with plastic, batch treatment of injection wells with scale and corrosion inhibitors, and transportation of carbon dioxide and water in separate lines to the injector.

Treating and foaming problems have occurred due to the nature of crude oil, low gravity and high viscosity, plus the carbon dioxide trapped in the oil. Continuous addition of a defoamer at the tank batteries has helped to alleviate this problem. As well, considerable heat and chemicals are needed to separate the oil and water in some cases.

Excessive gas production and/or early gas breakthrough problems have been reported. The WAG process with a WAG ratio above unity was found to be the best solution, with the added benefit of reduced water production and improved injection profiles. Excessive water production was also reduced by maintaining a high back-pressure on the formation, which also reduced recompression costs on the reinjected carbon dioxide (16,52). Gas channeling problems were successfully treated by the addition of a gelling agent to preclude gas migration through microfractures (46,51).

Criteria for reservoir selection - carbon dioxide is not a substitute for steam. Immiscible carbon dioxide flooding is not a substitute for thermal EOR techniques for heavy oils. Target reservoirs for the application of immiscible carbon dioxide flooding are those with oils too heavy to achieve miscibility with carbon dioxide and too deep and/or thin for economic and practical application of thermal methods, such as steam injection, and to a lesser extent, in situ combustion.

Immiscible carbon dioxide flooding projects have been targeted for reservoirs with the following characteristics:

Viscosity (@ res. cond.)	mPa·s	100-1000
Oil Gravity	°API	20-25
Oil Density	kg/m^3	904-1000
Fraction of oil remaining to be flooded prior to EOR	%PV	> 50
Oil Content	$m^3/ha{\cdot}m$	> 750
Porosity x Oil Saturation	—	> 0.08
Depth	m	> 300
Thickness	m	< 10
Initial Reservoir Pressure	MPa	> 6.90
Permeability	μm^2	> 0.20

The above parameters are generalized and are by no means fixed limits on the applicability of the immiscible carbon dioxide process. It is also important to note that the criteria above must be weighed equally with geology and economic considerations for each particular field under study.

Klins (11) presented a table of qualitative observations for fields being screened for immiscible carbon dioxide flooding. Reservoirs exhibiting a

homogeneous formation with thin pay zones and high dip are favoured. Low capacity and vertical permeability in horizontal reservoirs is also desirable. Reservoirs with a natural water drive, a major gas cap or a major fracture system should be avoided. Several authors (6,45,51,53) have noted that the most important criterion for a successful tertiary immiscible carbon dioxide flood is that a high oil saturation exist following a waterflood.

Approximately twenty projects listed in Table 1 are heavy oil projects. Oil viscosities vary from 30 to 100,000 mPa·s and oil gravities vary from 5 to 20°API. The majority of these projects were immiscible by nature due to the extremely high pressures that would be required to achieve miscibility. The majority of heavy oilfields have initial pressures ranging from 8 to 11 MPa at depths of approximately 1000 m. Several of these employed carbon dioxide as an additive in conjunction with steam.

Success. The great majority of the field tests listed in Table 1 were single well cyclic stimulations (denoted by '1-spot'). According to the respective reports, some of these were successful. Only five WAG type floods have been reported, at least two of which were successful (Wilmington and Lick Creek). Given the current understanding of the immiscible carbon dioxide flooding process, and the results of scaled models (1,25), it is believed that this process can find important applications in moderately viscous heavy oil reservoirs of Alberta and Saskatchewan.

OBSERVATIONS AND CONCLUSIONS

The immiscible carbon dioxide flooding process is well—suited for moderately viscous oils, with viscosities in the range of 100 and 2000 mPa.s, approximately. For lower viscosities, a waterflood may be more efficient than carbon dioxide; for higher oil viscosities, the rate of carbon dioxide transfer into the oil is too slow. The process should be considered for only those reservoir conditions, which are unsuitable for steam injection. If the process is applicable, it can recover a substantial amount of the in-place oil at a low carbon dioxide requirement, in the range of 500 to 1000 m^3 per m^3 oil.

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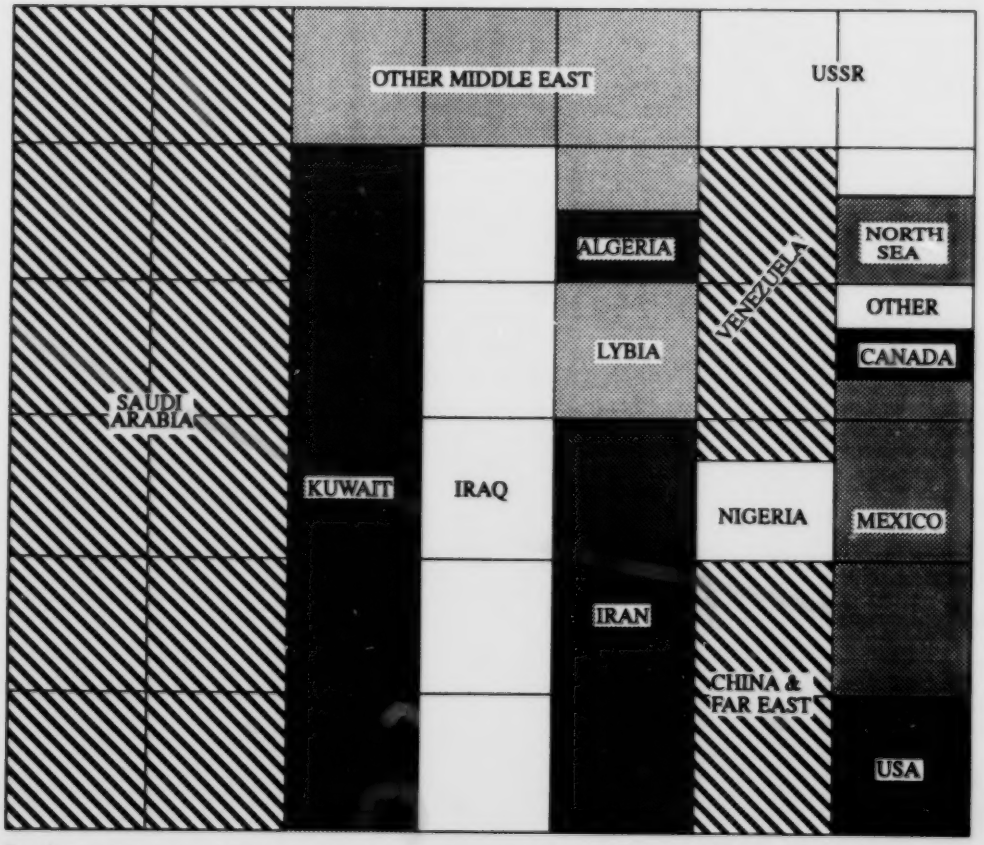
Area = World's oil reserves = 923 billion barrels*

* not including the recent 30-75 billion bbl discovery in Saudi Arabia



Each square represents one year's oil consumption of the world = 21.3 billion barrels

Fig. 1 - Oil reserves of the world in terms of yearly consumption.

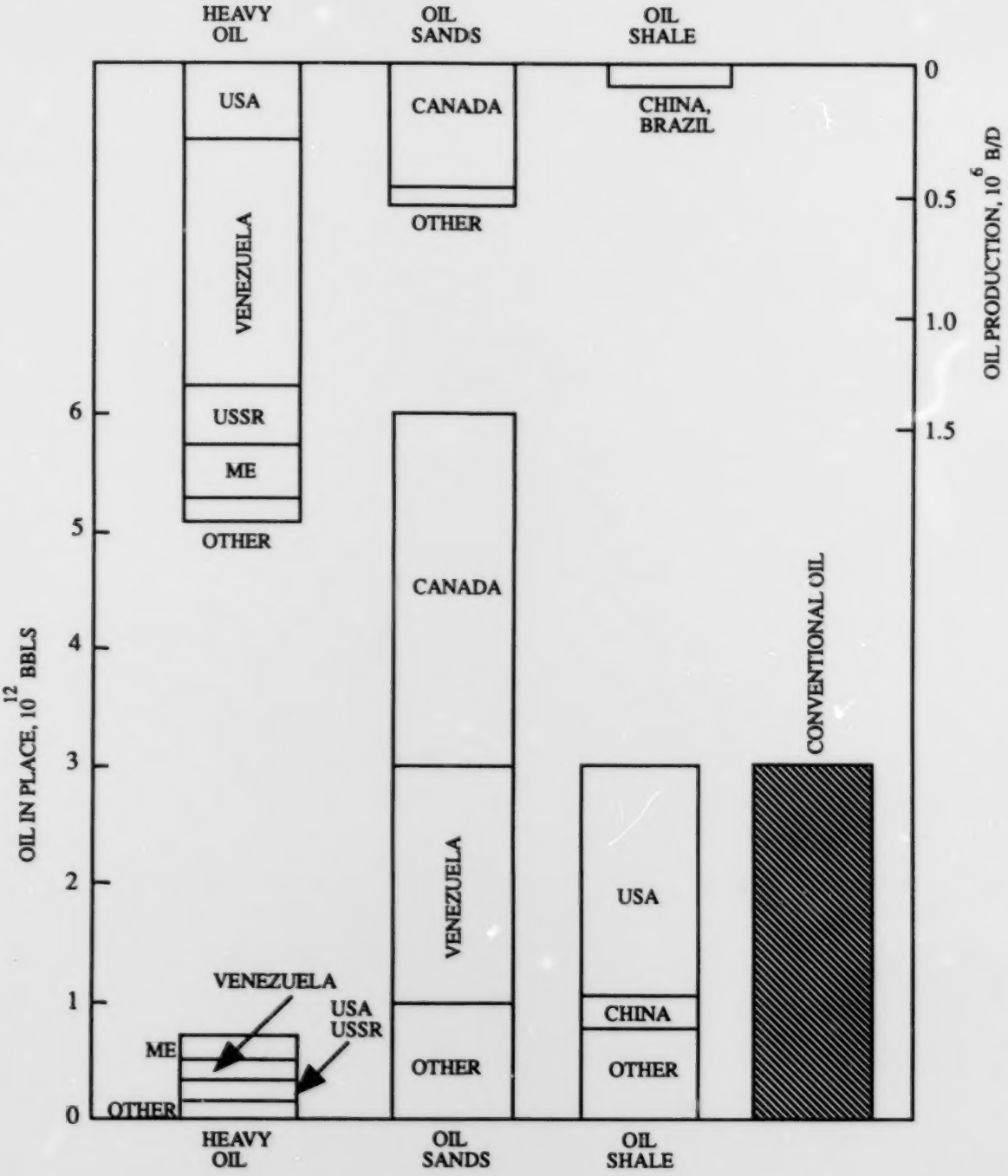


Fig. 2 - Heavy oil and oil sands resources of the world, and current production.

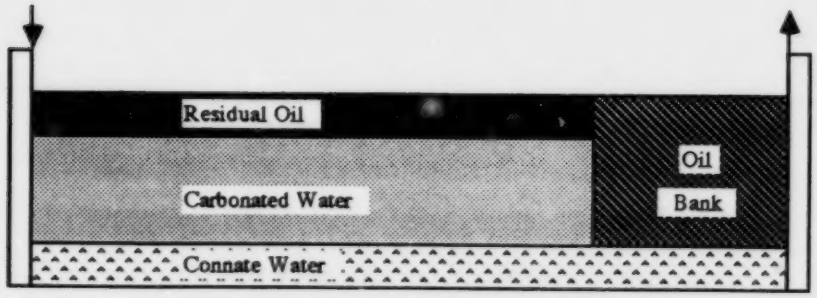


Figure 3a Carbonated Waterflooding (ORCO) Process

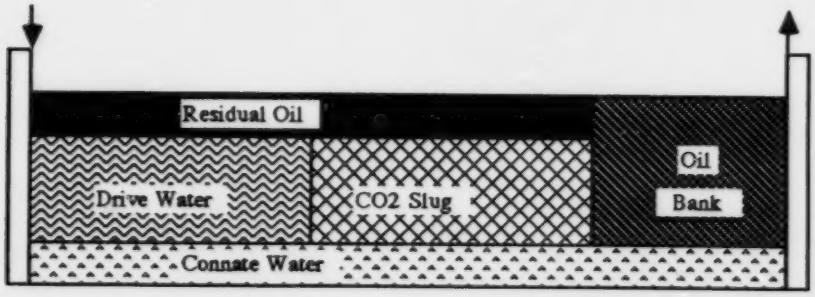


Figure 3b CO2 Slug and Water Drive Process

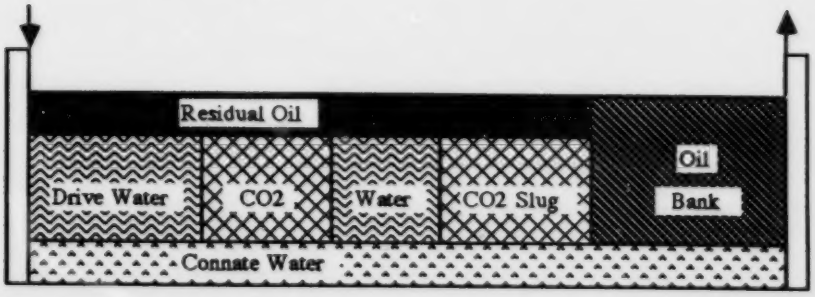


Figure 3c Water-Alternating-CO2 (WAG) Process

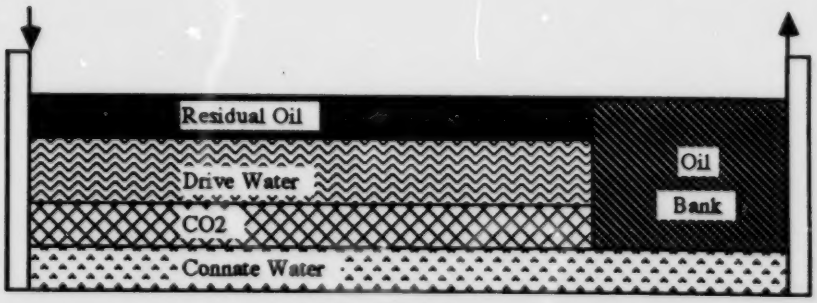


Figure 3d Simultaneous Water-CO2 Injection Process

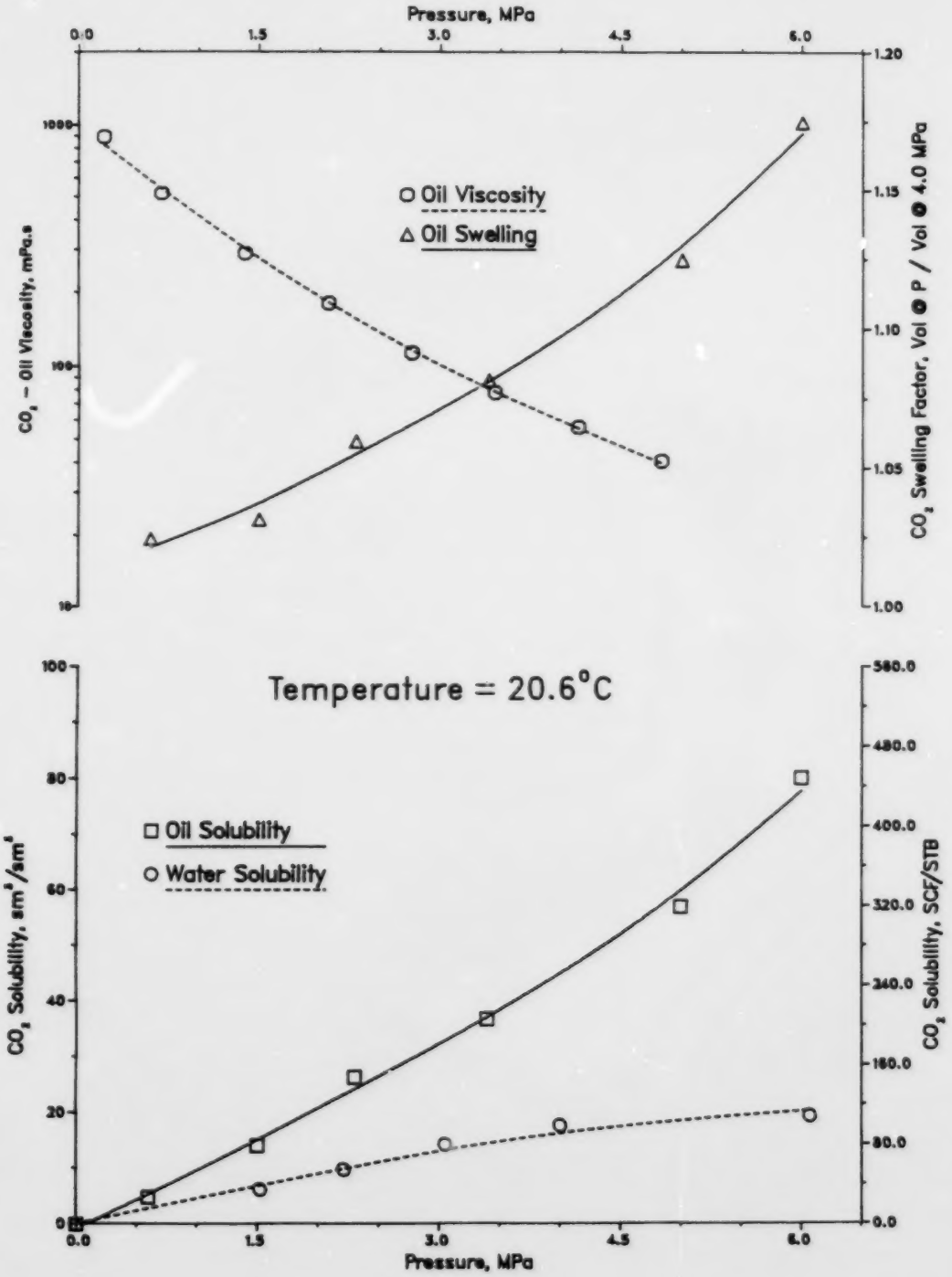


Figure 4 – Swelling Factors, Solubility and Viscosity of Carbon Dioxide in Aberfeldy Oil.

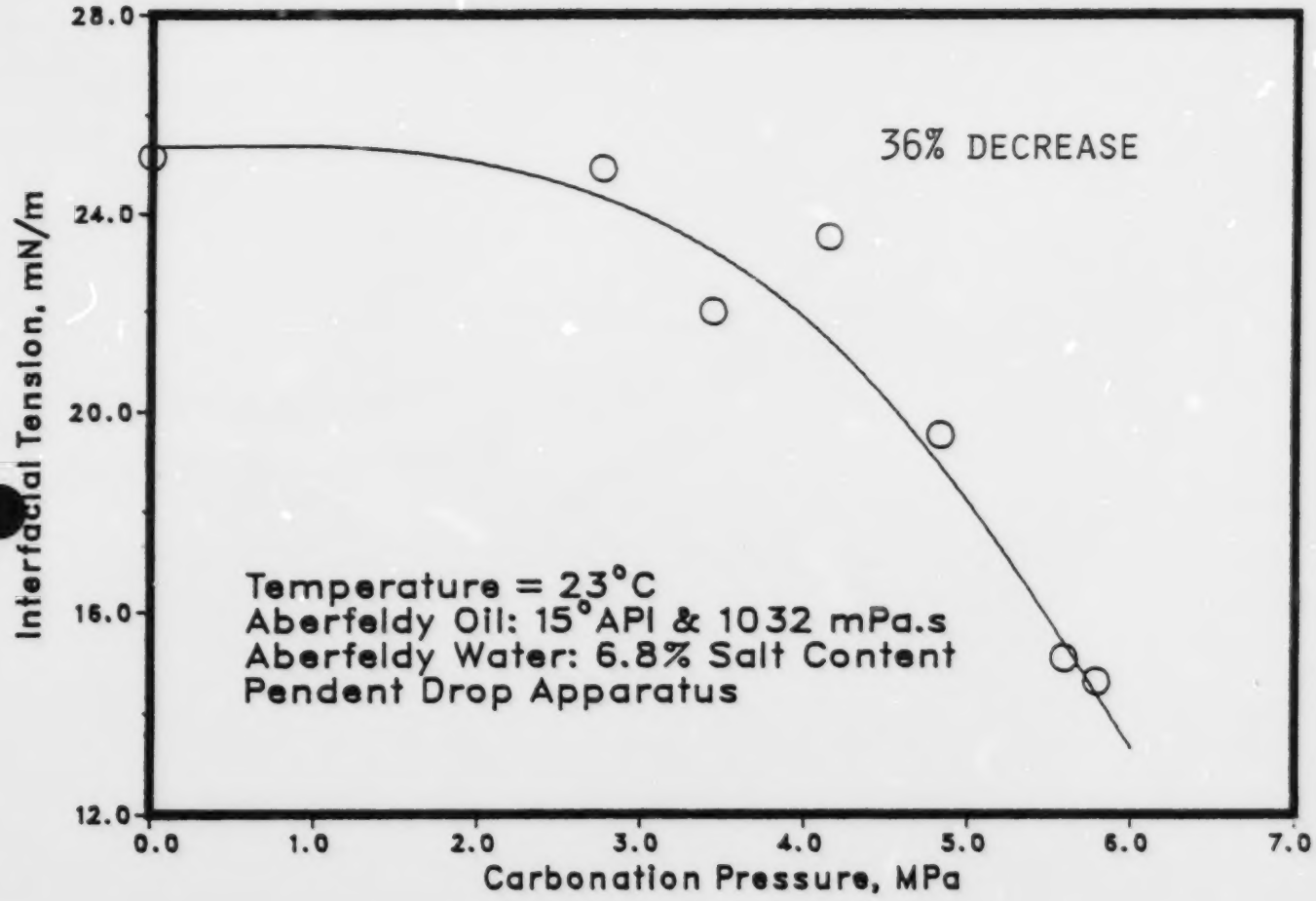


Figure 5 Effect of Carbon Dioxide on the Interfacial Tension Between Aberfeldy Oil and Formation Water.

Table 1
Immiscible CO_2 Field Projects

Initiation Date	Operator / Field	Formation Depth (m)	Formation Thickness (m)	Formation Lithology	Formation Porosity (%)	Formation Permeability (μm²)	Oil Gravity (°API)	Oil Viscosity (mPa·s)	So (%)	Sw (%)	Reservoir Temp. (°C)	Initial Res. Pressure (MPa)	Flood Pattern
03/87	Texaco/Bay De Chene*	2286	—	—	—	—	34.0	—	—	—	—	—	—
03/87	Texaco/Delacroux*	2408	—	—	—	—	38.0	—	—	—	—	—	—
03/87	Texaco/Lake Pelto*	2560	—	—	—	—	31.0	—	—	—	—	—	—
02/87	Texaco/Golden Meadow*	3078	—	—	—	—	37.0	—	—	—	—	—	—
02/87	Texaco/Bayou Fer Blanc*	4113	—	—	—	—	39.0	—	—	—	—	—	—
02/87	Texaco/Lafitte*	1219	—	—	—	—	21.5	—	—	—	—	—	—
01/87	Texaco/Lafitte*	1981	—	—	—	—	25.9	—	—	—	—	—	—
01/87	Texaco/Lafitte*	1324	—	—	—	—	28.0	—	—	—	—	—	—
06/86	Texaco/West Nancy*	4206	—	—	—	—	38.2	—	—	—	—	—	—
06/86	Texaco/Vermilion*	1585	—	—	—	—	40.5	—	—	—	—	—	—
06/86	Texaco/Vermilion*	1676	—	—	—	—	40.0	—	—	—	—	—	—
06/86	Texaco/Vermilion*	1829	—	—	—	—	33.5	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	3200	—	—	—	—	39.0	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	2987	—	—	—	—	37.5	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	3033	—	—	—	—	38.3	—	—	—	—	—	—
05/86	Texaco/West Delta 109*	3779	—	—	—	—	31.3	—	—	—	—	—	—
05/86	Texaco/Caillou Island*	3932	—	—	—	—	33.6	—	—	—	—	—	—
05/86	Texaco/Caillou Island*	3901	—	—	—	—	33.5	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	2632	—	—	—	—	38.3	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	2918	—	—	—	—	38.1	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	3200	—	—	—	—	37.1	—	—	—	—	—	—
04/86	Texaco/West Delta 109*	3048	—	—	—	—	37.4	—	—	—	—	—	—
04/86	Texaco/Leeville*	2194	—	—	—	—	36.1	—	—	—	—	—	—
04/86	Texaco/Caillou Island*	4267	—	—	—	—	37.1	—	—	—	—	—	—
02/86	Texaco/Bourie*	3130	—	—	—	—	37.0	—	—	—	—	—	—
02/86	Texaco/Bonnet Carre*	2865	—	—	—	—	37.0	—	—	—	—	—	—
1986	Westgrowth/Little Bow*	1067	—	—	—	—	25.0	—	—	—	—	—	—
12/85	Chevron/Timbalier Bay	1486	—	sandstone	32.0	0.49 - 2.46	26.0	17	60.0	40.0	59.0	—	—
11/85	Marathon/Yscas	335-518	—	dolomite	17.0	0.017	30.0	5.5	—	—	27.8	—	—
10/85	Amoco/San Andres	1372	—	dolomite	13.0	0.001	32.0	—	—	—	37.8	—	—
06/85	Texaco/West Delta 109*	3048	—	sandstone	27.0	0.202	37.3	0.26	50.0	—	90.0	—	—
09/85	Amoco/Prentice NE	1813-2042	21.3-29.6	dolomite	5.7-12.4	(2.0-6.8)E-3	28.0	—	—	—	46.7	—	5-spot
06/85	Texaco/West Delta109*	3200	—	sandstone	30.0	1.875	36.5	0.28	50.0	—	93.3	—	—
06/85	Texaco/West Delta 109*	3657	—	sandstone	27.0	1.019	34.1	0.25	50.0	—	103.3	—	—
06/85	Texaco/West Delta 109*	3200	—	sandstone	29.7	0.067	37.0	0.3	50.0	—	98.9	—	—
06/85	Texaco/S.Marsh Island B6	3414	—	sandstone	29.6	0.319	34.0	0.3	50.0	—	97.8	—	—
1985	AGIP/Pisticci	1981	—	dolomite	18.0	0.197-0.493	11.0	23	60.0	40.0	67.2	—	1-spot
12/84	AGIP/Ponte Dirillo	2895-2956	—	dolomite	5.0-6.4	—	10-15	30	—	—	99.4	—	—
04/84	Texaco/Lake Barre	3962	39.6	sandstone	25.0	0.138	33.0	0.4	—	—	113.3	—	1-spot
02/84	Union Pacific/Wilmington	762	—	sandstone	34.0	0.438	14.0	283	51.0	49.0	30.6	—	—
1984	Texaco/Lafitte	2722-2744	4.9	—	27.0	0.247	32-33	0.7	—	—	—	27.21	1-spot
1984	Arco/Jeanerette	1829-1981	6.1-9.1	sandstone	30.0	—	36.0	0.5-0.8	—	—	73.9	—	1-spot
1984	Texaco/Bayou Sale	3048	3.4	—	30.0	0.148-1.579	34.0	0.38	—	—	93.3	—	1-spot
1984	Texaco/W.Cote Blanche	2438	13.1	—	29.0	0.271	28-30	0.8	—	—	82.2	—	1-spot
1984	Texaco/Liberty South	2371	9.1	sandstone	22.0	0.013	37.0	1.6	40.0	20.0	79.4	26.30	1-spot
1984	Amoco/Gregoire Lake	183	13.7	sandstone	20.0-35.0	—	5-8	100000	—	—	10.0	—	4-spot
1984	Pan Canadian/Lindbergh	610	7.6-12.2	sandstone	—	0.493-1.974	12.0	10000	—	—	22.8	—	1-spot
1984	TPAO/Camurlu	1250	64.0	dolomite	11.0-16.0	0 - 4.93E-3	10-12	284	77.0	23.0	74.4	12.41	1-spot
1984	TPAO/Bati-Raman	1311	64.0	dolomite	14.0-20.0	0.197-1.974	9-15	300-1000	79.0	21.0	65.6	12.41	1-spot
1984	Bow Valley/Cold Lake	457	24.4	sandstone	30.0	1.480	—	100000	—	—	15.6	—	7-spot
12/83	Gulf/Pittsburg	1032-1158	3.0	sandstone	23.0	0.233-0.887	14.0	2200	65.0	30.0	48.9	11.14	1-spot
12/83	Gulf/Heidelberg	1342	—	sandstone	25.0	0.073	20.0	15	—	—	65.6	—	1-spot
12/83	Chevron/Heidelberg	1342	—	sandstone	25.0	0.073	20.0	15	—	—	65.6	—	1-spot
11/83	Chevron/Pittsburg	1052-1158	3.0	sandstone	23.0	0.233-0.887	14.0	2200	65.0	30.0	48.9	11.14	1-spot
11/83	Westgrowth/Retlaw	—	1.8-2.4	sandstone	18.0	0.049	23.0	8-10	—	—	35.6	11.38	7-spot
10/83	Texaco/Plymouth	1419	—	sandstone	31.0	0.345	23.3	2.3	31.3	30.8	63.3	14.16	1-spot
08/83	XTRA/Wilmington FB1	1036	11.3	sandstone	28.0	0.099-0.987	14.0	179	66.0	34.0	58.9	8.96	—
08/83	Santa Fe Energy/Raymond	2408	2.7-6.7	dolomite	8.2	0.013	40.0	0.43	71.3	—	86.7	—	—
07/83	Texaco/West Columbia	792	45.7	sandstone	30.0	0.553	30.0	8	36-48	15.0	46.1	9.96	1-spot
07/83	Texaco/Magnet Withers	1660	20.4	sandstone	23.0	0.295-19.73	26.0	2.3	35.0	27.2	67.8	17.29	1-spot
06/83	Exxon/Hewitt Ranch	1378	15.2	sandstone	24.0	0.987-1.480	19.0	21-30	65.0	20.0	71.1	13.07	1-spot
05/83	Texaco/Pickett Ridge	1402-1426	2.7	sandstone	30.0	0.136-1.184	25.0	2.5	29.0	20.0	58.9	14.72	1-spot
05/83	Texaco/Talco	1154	7.6	sandstone	25.0	0.383	23.0	20-25	50.0	20.0	63.9	4.48	1-spot
03/83	Texaco/Withers, North	1600-1634	2.1	sandstone	25.0	1.036-3.223	25.7	2.45	35.0	20.0	62.8	16.88	1-spot
05/83	Texaco/Withers C-sand	1617-1621	2.4	sandstone	25.0	0.395-3.223	25.3	2.9	32.0	20.0	63.9	16.72	1-spot
01/83	Texaco/Thompson	1554	7.6	sandstone	27.0	0.099-0.987	25.2	2.7	42-65	27.0	57.2	16.86	1-spot
01/83	Texaco/Pierce Ranch	1496	3.7	sandstone	24.4	0.911-1.924	24.4	8.56	48.0	31.0	68.3	14.30	1-spot
10/82	Texaco/Manvel F.B.I.	1524	6.1	sandstone	30.0	0.987	26.7	7.2	45.0	15.0	65.0	16.48	1-spot
10/82	Texaco/Manvel, East (3)	1219-1244	4.9	sandstone	30.0	0.395-0.493	25.0	4.4	42-65	15.0	65.0	13.20	1-spot
07/82	Union Texas Pet./Wellman	2835-2987	61.0-103.0	dolomite	8.0-9.6	0.001-0.987	43.0	0.5-0.7	55.0	22.0	60.1	27.72	—
06/82	Husky/Wainwright	457	4.1	sandstone	37.0	0.987-1.974	12.0	2000	—	—	21.1	—	1-spot
06/82	UNOCAL/East Coyote	914-1524	76-122	sandstone	—	—	16-26	—	—	—	—	—	—
03/82	LBODC/Wilmington FB5	701	15-30	sandstone	30.0	0.099-0.987	13-15	200-500	37.0	25.0	48.9	6.90	line-drive
02/82	Cities Service/Welch	1478-1554	30.5	carbonate	9.25-13.2	0.001-0.014	34.0	2.38	47.0	27.0	35.6	—	—
1982	? / Brade (Rumania)	1016	7.0	sandstone	25.0	0.247	24.0	18	–	–	40.0	—	—
11/81	Aminoil/Huntington Be.	762	—	sandstone	24.0	0.247	18.0	175	–	–	54.4	—	1-spot
03/81	Champlin/Wilmington FB3	762-781	12.8	sandstone	24.0	0.459	14.0	283	51.0	25.0	50.6	7.55	—
03/81	Union Pacific/Wilmington	762	—	sandstone	24.0	0.458	14.0	283	51.0	49.0	50.6	—	—
02/81	Phillips/Vacuum	1372	—	dolomite	11.7	0.011	38.0	1	70.0	–	38.3	—	—
01/81	Petromse Inc./Rankin	2408	9.1-11.6	sandstone	27.0	0.296	37.0	0.6	55.0	35.0	88.9	24.48	inv 7-spot
1981	Husky/Kitscoty	549	—	sandstone	31.0	1.974	13.0	7000	—	—	21.1	—	1-spot
01/80	OKGT/Nagylengyel	2256	—	dolomite	2.0-3.0	0.987	16.0	92	—	—	48.9	—	gas cap
1980	Amerada Hess/Estes	1463-1585	4.6-4.9	sandstone	28.4	0.284-0.296	22.0	16	51.0	35.0	68.9	13.79	inv 5-spot
03/79	Elf Aquitaine/Grenade	2347	—	dolomite	—	—	11.0	1000	99.0	—	71.7	—	—
1979	Shell/Western/Weeks Island	3890	—	sandstone	23.0-26.0	0.985-1.774	33.0	0.34-0.60	22.0	7.0	107.2	34.13	—
01/75	Phillips/Lick Creek	762-777	2.6	sandstone	30.3-33.0	1.184-1.480	17.0	160-188	55-68	32-45	45.6	8.27	irregular
04/72	Shell Western/Cromett	1615-1646	18.3-24.4	dolomite	22.0	(3.0-5.0) E-3	44.0	0.36-0.40	34.0	35.0	41.1	17.24	inv 9-spot
1969	U.S. Oil&Ref. Co/Ritchie	792	2.7	sandstone	31.0	2.714	16.0	195	80.0	20.0	52.2	8.62	irregular
1958	Oil Rec.Corp./Bartlesville	—	—	—	—	—	—	—	—	—	—	—	5-spot
1951	Bradely Prod. Corp./Reno	—	—	—	—	—	—	—	—	—	—	—	5-spot
09/49	Bradely Prod. Corp./ ?	—	—	—	—	—	—	—	—	—	—	—	5-spot

Carbon Dioxide Miscible Flooding Experience In The Joffre Viking Field

Derril J. Stephenson, President, Vikor Resources Ltd.

Abstract. An experimental CO_2 miscible flood in the Joffre Viking Field has produced in excess of 850,000 barrels of oil from a reservoir that had previously been waterflooded to its economic limit and abandoned. The project commenced CO_2 injection in January 1984. Injection of up to 25% HCPV per year permitted rapid evaluation of a pilot using commercial well spacing. Various injection schemes were tested at Joffre including water alternating CO_2, continuous CO_2, simultaneous CO_2/water and foamed CO_2. History matching of the production performance has been useful in improving the understanding of the process at Joffre; however existing numerical simulators had to be used in a unique manner to adequately model the reservoir performance. The original pilot project and subsequent experimental expansions are described including operating experience with the surface facilities, pipelines and wells. Capital and operating costs for a potential carbon dioxide miscible flood in Central Alberta compare favorably with costs for a typical small commercial in-situ steam project producing at similar oil production rates.

INTRODUCTION

In 1983 the abandoned Joffre Viking field, located northeast of Red Deer, Alberta (Figure 1), was reactivated for Canada's first miscible carbon dioxide flood. The Joffre Viking is a sandstone reservoir deposited as a barrier bar in Cretaceous time. The pool is 1500 m (5000 ft) deep and stretches 37 km (23 miles) by 2.5 km (1.5 miles) and has an average pay of 3 m (10 ft). The field contained an estimated original oil in place of 14.8×10^6 m^3 (93×10^6 barrels) of 813 kg/m^3 (42°API) sweet crude oil. Average porosity of the pool is about 13% and permeability ranges over 1000 md and averages 500 md. Connate water saturation was 30% and the GOR was 44 m^3/m^3 (250 SCF/Bbl).

After discovery in July 1953 the field was developed on 16 ha (40 acres) per well spacing with primary recovery by fluid expansion and solution gas drive. In 1957 the field was unitized and a line drive waterflood initiated. By the mid 1960's after recovering 42% of the original oil in place, the field had been produced to its economic limit and was abandoned.

The potential for tertiary oil recovery in the Joffre Viking was recognized and in the early 1980's laboratory testing and reservoir simulation determined its suitability for tertiary oil recovery using a miscible carbon dioxide flood[1]. These model studies included history matching of the primary and secondary performance of a 1375 ha (3400 acres) area of the field containing 85 wells bounded by the water injection lines (Segment B in the original unit). Commercial performance of a miscible carbon dioxide flood was then predicted using the model. An area in the middle of segment B, containing 130 ha (320 acres) was selected for the Pilot and a performance prediction extracted from the model studies. The Joffre Viking Tertiary Oil Unit was formed April 1, 1983, on an area large enough to support commercial development using readily available CO_2 sources.

In June 1983 an agreement was reached with the Alberta Oil Sands Technology and Research Authority (AOSTRA) to fund 75% of the net cost to implement a miscible CO_2 pilot project in the field. The Pilot utilizes two adjacent inverted five spot patterns (Pattern A & B) on 32 ha (80 acre) per well spacing. In July 1985 the Joffre Viking Tertiary Oil Unit started Pattern C and in June 1988 Pattern D commenced operation. Patterns C & D (Phase II) are adjacent truncated inverted 9 spot patterns with a total of eleven production wells on 64 ha (160 acre) per well spacing with two central injection wells. AOSTRA has a 20% interest in Pattern C and Pattern D.

After laboratory testing of various surfactants in September, 1988 a mobility control test using foam generated by surfactants was initiated in Pattern B. Planned field testing of foams was completed at the end of 1989 and engineering evaluation of the performance is continuing. AOSTRA funds 75% of the mobility control test net costs.

Significant oil production from the carbon dioxide flood has been observed in all patterns in

Joffre. This paper will discuss this performance and our operating experience with the flood.

RESERVOIR PERFORMANCE

Pilot. The Pilot area was selected because the waterflood history match[1] indicated that it was an area of highest mobile oil saturation therefore, it would produce maximum revenue to offset pilot costs. The Pilot utilizes two adjacent inverted five spot patterns (Pattern A & B) on 32 ha (80 acre) per well spacing, containing six production wells and two water/CO_2 injection wells. Four peripheral, pressure maintenance water injection wells were located on the original line drive water injection well locations.

Baseline productivity commenced in December 1982 and source water injection to repressure the reservoir to above the minimum miscibility pressure of 12,000 kPa (1740 psig) started in September 1983. Carbon dioxide injection into the Pilot commenced January 14, 1984. Carbon dioxide and water were injected alternately into the center well of each pattern in the Pilot until October 1986. The first phase of the pilot program was completed in January, 1988.

Figure 2 illustrates the sharp increase in oil production and reduction in WOR on response to the carbon dioxide injection. Some of the significant changes evident on the figure were caused by deliberate operating decisions. For example, the reduced oil production in late 1984 was caused when withdrawals were reduced to match curtailed CO_2 supplies. Figure 3 shows the predicted cumulative oil production for the Pilot compared to the actual. Oil recovery from the Pilot was lower than anticipated primarily because of lower mobile oil production. Modelling of baseline and pilot productive performance suggest that the mobile oil saturation was only 40% of that originally predicted[2]. The reduction in mobile oil saturation is attributed to a higher residual oil to waterflood, mobile oil more uniformly distributed and possibly lower original oil in place than predicted.

A concern that water blocking would create a major problem in the reservoir led to the selection of large, 0.1 HCPV, slug sizes of carbon dioxide alternating with water in the Pilot. Experience suggests that these large slugs were ineffective in mobility control and contributed to the actual tertiary performance deviating significantly from predicted. The original simulation study predicted slower initial tertiary oil production response and higher later response than experienced in the field. Analysis of the Pilot oil and carbon dioxide response during history matching required significant modifications to conventional modelling techniques to account for fluid flow in the carbon dioxide and water swept zones of the reservoir. After these modifications the numerical simulator could be used for development planning.

Another reason for the reduced performance was greater than expected heterogeneity in Pattern A of the Pilot. While geologically two distinct sands were evident; history matching primary and secondary recovery performance suggested that these two sands were in excellent communication. Operating experience showed this was not the case. In September, 1986 to correct this problem the 16-20 production well was converted to an injection well. A significant volume of oil was recovered from the 14-20 production well, which is completed in both sands. Because of the unconfined nature of this area recovery was less than anticipated and injection was terminated in August 1987.

In spite of these problems performance of the Pilot has been exceptional. Figure 4 compares pilot reservoir, fluid parameters and actual performance of the Pilot from start up until the end of 1989 to the predicted ultimate performance of 12 field scale and 9 producing pilots in the United States[3]. The only two projects in the United States expected to exceed the current percentage oil recovery in the Joffre Pilot are North Cross, which had not been waterflooded, and Little Creek where the largest reported pore volume of carbon dioxide was injected. Recovery from the Pilot has reached 33% of remaining oil in place at the beginning of the tertiary flood. Oil production from the Pilot peaked earlier than predicted and by March 1985 rates were in excess of 60 m^3/d (400 BOPD). In some wells a twenty fold increase in oil production was experienced with response to CO_2 injection. Carbon dioxide utilization has been excellent with about 1.6 Mg of gross CO_2 injected per m^3 of oil produced (4.9 MCF/Bbl). While we experienced early production of CO_2, overall carbon dioxide retention in the reservoir has been excellent with less than 38% of injected CO_2 produced to date.

Any injectivity or productivity problems that occurred in the wells were easily remedied, therefore we have successfully injected at up to 25% hydrocarbon pore volume per year in the Pilot. These rates were selected to permit early and complete evaluation of the Pilot in a short period of time on commercial well spacing. A significantly larger hydrocarbon pore volume of CO_2 has been injected than originally proposed.

Pilot foam test. Our analysis of the reservoir suggested that significant pore volume remained uncontacted by CO_2 and in 1988 agreement was reached with AOSTRA to test the effectiveness of using foams in the Pilot to control CO_2 mobility. The Alberta Research Council was contracted to screen potential surfactants for use in Joffre[4]. This screening identified potential candidate surfactants with excellent adsorption and fluid compatibility characteristics. In the fall of 1988 two of the surfactants were field tested at various

concentrations and injection techniques with careful monitoring of downhole injection pressure to evaluate performance[5]. The bottomhole pressure monitoring system used in this test provided excellent results allowing us to further optimize surfactant concentration and injection techniques. This short duration test proved the ability of surfactants to generate significant pressure drop in the reservoir near the injection wellbore, the next step was to determine if this would translate into improved conformance and more oil in the tank.

In early 1989 a more extensive surfactant injection program was initiated to test foam mobility control performance by monitoring production response[6]. Injection fluids were traced and injection and production carefully monitored throughout the duration of this test. The test has been concluded and results are currently being analyzed. Oil production response was lower than anticipated however, the test has improved our understanding of fluid flow in the reservoir and helped optimize injection fluid quality. Further work will be required to improve propagation through the carbon dioxide swept zone.

Phase II (Patterns C & D). The Joffre Viking Tertiary Oil Unit developed Pattern C in mid 1985. This truncated inverted 9 spot pattern consists of six production wells on 64 ha (160 acre) per well spacing surrounding a central injection well. A single peripheral water injection well was located to the west of the pattern. Continuous injection of carbon dioxide was undertaken in this pattern until June 1988 when water injection commenced.

In June 1988 Pattern D, another truncated inverted 9 spot pattern with seven production wells on 64 ha (160 acre) per well spacing surrounding a central injection well started operation. Simultaneous injection of carbon dioxide and water is being tested in Pattern D to compare to the water alternating carbon dioxide and continuous carbon dioxide injection previously evaluated in other patterns.

The expansion Patterns C & D have responded favorably to the injection of CO_2. Of particular interest are the 4-30 and 12-19 wells in Pattern D which were converted from Pilot peripheral water injectors. Over 810,000 m^3 (5.1 million barrels) of water had been previously injected into these wells in the original waterflood and Pilot operation. Both of these wells initially produced 100% water; however after a few months the 4-30 well commenced oil production and reached rates of 16 m^3/d (100 BOPD) and has produced over 5000 m^3 (32,000 barrels) of oil since response. The 12-19 well responded much later and production rate continues to increase. Preliminary production indicates that simultaneous carbon dioxide and water provides the best mobility control for Joffre. Various carbon dioxide/water ratios have been tested and an optimum range selected.

INJECTION SYSTEMS

The project injection system[7,8] including gaseous carbon dioxide from Alberta Gas Ethylene Company (AGEC), liquid CO_2 and produced gas, as well as produced and source water injection is shown schematically on Figure 5. The CO_2 sources were commingled at the central battery and then distributed to the injection wells. Until the end of 1986, liquid CO_2 was trucked to the site to supplement injection requirements for the Pilot. The CO_2 was stored in refrigerated bullets and pumped to injection pressure by cryogenic triplex pumps.

Source water from the Red Deer river and produced water are commingled upstream of the water treatment plant and distributed to the injection wells. The water is filtered, chlorinated and oxygen scavenged before injection into the formation using conventional plunger pumps.

Saturated, gaseous CO_2 is available from Alberta Gas Ethylene Company (AGEC) Joffre Plants No. 1 and No. 2. Oil flooded rotary screw compressors compress up to 150 Mg/d (2.8 MMSCF/d) of CO_2 from atmospheric pressure off amine regenerator reflux accumulators to a discharge pressure of over 1000 kPa(g) (145 psig). As this CO_2 is over 98% pure, no CO_2 separation facilities are required to condition the gas as a miscible agent.

Over the past six years these screw compressors have experienced some operating problems. Low suction pressure and high suction temperature necessitate high discharge temperatures to prevent condensation of water in these single stage, high compression ratio machines. Oil usage has been significantly higher than anticipated and major repairs have been required to both the electric drives and compressors.

Because the GOR in Joffre is relatively low and the produced gas rich in C_2+ it was determined that the produced carbon dioxide and hydrocarbon gas could be re-injected as a miscible fluid without further separation when CO_2 production occurred. Slim tube testing has confirmed the miscibility of the produced gas stream. Therefore the central battery injection facilities were designed to allow the same compression to be used to recycle the first stage separator gas and compress the CO_2 from AGEC. A small oil flooded rotary screw compressor was installed to conserve the CO_2 flashed off the oil in the low pressure separators.

In the central battery produced gas and the CO_2 from AGEC are commingled. The combined stream is then compressed from 700 kPa(g) (100 psig) to between 7000 and 9500 kPa (1000 to 1375 psig) by electrically driven, high speed, separable, lubricated, reciprocating compressors.

Carbon dioxide is dehydrated to less than 225 mg/m^3 (14#/MMSCF) in standard process, triethylene glycol (TEG) dehydrators immediately after

the first stage of compression, at a pressure of approximately 3000 kPa (435 psig). The gas is dehydrated at this pressure because, as shown in Figure 6, carbon dioxide, unlike hydrocarbon gas, reaches a minimum in its water carrying capability and then increases with rising pressure[9]. There is also an economic advantage to dehydrating as early in the injection scheme as possible thereby minimizing the need for expensive corrosion resistant materials. Maximum interstage cooling should be utilized upstream of the dehydrator to ensure a reasonable contact temperature. The water content of the dehydrated CO_2 is monitored daily using an electronic probe. Experience has shown that sampling procedure is critical to accurate determination of water content. Pressure drop upstream of the probe must be minimized and CO_2 must be in the gaseous phase. No corrosion or hydrate problems have been experienced in the carbon steel piping in the injection system.

Figure 7 illustrates different configurations we have used in injection wells. All have performed satisfactorily under both water alternating CO_2, continuous CO_2 and simultaneous CO_2 and water injection.

Overall the CO_2 injection facilities have performed well with operational problems similar to conventional gas compression and dehydration plants.

METERING OF CO_2

Considerable difficulty metering CO_2 has been encountered by a number of operators, particularly at conditions near the critical point of CO_2. Comparatively good success metering CO_2 has been experienced in the the Joffre flood at the following meter points:

1. Sales carbon dioxide from AQEC — This CO_2 stream is in a gaseous form and is measured by an orifice meter at approximately 1000 kPa (145 psig) and 30°C (85°F) in accordance with AGA regulations.
2. Produced gas CO_2 concentration is monitored daily using an infrared analyzer to allow a produced gas density to be calculated from an empirical correlation. Conventional orifice meters are then used on all produced gas streams with the rates calculated in accordance with AGA regulations, corrected to the calculated density.
3. High Pressure CO_2 streams are measured with mass flow meters at temperatures ranging from 10 to 40°C (50 to 104°F) and at pressures ranging from 7000 to 9500 kPa (1000 to 1375 psig) in the central battery.
4. At one injection well we have installed an orifice meter on the injection CO_2 stream. Injection at this location is close to the critical point for CO_2; however by utilizing precise CO_2 properties and a basic formula for compressible fluids in orifice meters, the stream has been satisfactorily measured.

Overall CO_2 meter balance has averaged approximately 1.5% difference between the sum of the source meters and the mass meters on the injection lines. The wellsite high pressure CO_2 orifice meter has been calibrated successfully against a mass flow meter in the battery.

PRODUCTION SYSTEMS

Figure 8 illustrates the major components of the production system.

Starting in 1983 six production wells in the original Pilot were produced through 88.9 mm (3") Alclad coated aluminum flowlines. When Pattern C was developed in 1985, 88.9 mm (3") Alclad coated aluminum flowlines were again utilized to produce the wells to field headers. Production is grouped at field headers and transported to the central battery through a 168.3 mm (6") internally and externally coated carbon steel pipeline joined using Mechanical Interference Fit techniques.

When Pattern D was developed in 1988, 88.9 mm (3") internally and externally coated Mechanical Interference Fit carbon steel flowlines were selected. The coated steel gathering lines and flowlines have been trouble free.

Production from the Pilot and Phase II is two stage separated in parallel train, 700 kPa (100 psig), and 200 kPa (30 psig) pressure separators. Normally no emulsions are produced so all produced water is separated in the inlet separators. A treater was installed in the original Pilot; however for the Phase II expansion only second stage separation was provided. Oil is stored in two 120 m^3 (750 barrel) oil storage tanks and transported for sale via Gulf Alberta Pipeline through a lease automatic custody transfer unit. Well test separators are also three phase and have provided excellent accuracy with oil proration factors averaging less than 0.35% since the start of the operation. Produced water is stored in a 480 m^3 (3000 barrel) water storage tank for treating and reinjection into the Joffre Viking reservoir. This tank also provides settling to recover produced oil carried over from the separators.

The battery has operated successfully over significant variations of rate, GOR and WOR. Figure 2 shows monthly variations: daily swings have been significantly higher.

The Pilot production wells were redrilled and completed using beam pumps and a combination of co-rod and conventional scrappered sucker rod strings in 73 mm (2 7/8) tubing with rod insert pumps. In 1985 when Pattern C was developed, two of these wells had high fluid rate requirements and consequently submersible pumps were run on

internally coated 73 mm (2 7/8") tubing. The remaining four wells were completed with beam pumps, using scrappered sucker rod strings and either rod insert pumps or tubing pumps. The five production wells developed for Pattern D were all completed with beam pumps. Rod inserts were installed with either co-rod or scrappered sucker rod strings. Two of the Pattern C wells were converted to flowing wells for part of their life[10].

Changes in the design of components in the production wells continue and significant improvements have been made in this most problematic area of our operation including:

1. Better elastomer materials for high carbon dioxide partial pressure operation[11].
2. Material selection and spacing of scrappers on rod strings has improved.
3. Sucker rod and co-rod string material and design have improved.
4. Iron level monitoring criteria has been modified and corrosion inhibition programs optimized.
5. Alternative materials have been selected for key bottomhole pump components.
6. Dewaxing procedures in wells have been improved.
7. Satisfactory control of freezing in high carbon dioxide producing wells has been achieved.
8. Control of bottomhole near wellbore plugging because of scale and paraffin.

Further development to resolve apparent rod wear problems and to enhance bottom hole pump life could reduce operating costs in carbon dioxide flood production wells.

Injection well operation has been relatively trouble free. Intermittent injectivity problems have occurred in one of the carbon dioxide injection wells but they have been easily remedied. Both the water and carbon dioxide injectivities have improved dramatically over time in all carbon dioxide injection wells.

Materials. The two 114.3 mm Alclad coated aluminum pipelines[12] carrying the wet CO_2 stream from the AGEC plant to the Central Battery have had no problems during six years of operation.

In the injection system all piping, valves and vessels in a corrosive environment have been constructed from 304L stainless steel. Carbon steel is used in non-corrosive environments on the compressor package and in the CO_2 injection system when fluid temperature and/or pressure prevent the condensation of water vapour, or after the CO_2 has been dehydrated.

As the CO_2 and water can mix at the injection well, all piping and wellhead equipment is constructed of corrosion resistant materials. A thin film phenolic epoxy internal coating was selected for the carbon dioxide and water injection well tubing strings. Tubing threads must be sealed with a teflon-based dope as hydrocarbon-based dope can be miscible with the CO_2 and washed away. Contrary to some other operators' experience, our injection wells have been relatively trouble free. We have had no coupling leaks or tubing corrosion and our only failure has been a packer leak caused by corrosion of external uncoated packer parts of an internally coated packer. The stainless steel packers utilized in the Pilot have been trouble free and there have been no problems with the elastomers in the packers.

In late 1985 some problems were experienced and by 1987 significant corrosion of the 88.9 mm (3") Alclad coated aluminum flowlines had occurred in the water wet portions of the lines. In order to rejuvenate these lines 60.3 mm (2") fibreglass laminate pipe was pulled through the aluminum flowlines to several of the production wells. Minor problems with the fibreglass lines resulted from the difficulty in supporting the pipe adequately to compensate for its limited shear strength.

A portion of the flowlines from two of the wells in the Pilot are bare carbon steel pipelines installed during the 1950's for the original waterflood development. These bare carbon steel pipelines have performed very well over the seven years of operation with the only problems being external corrosion in the heat affected zone of the longitudinal weld of the ERW pipe we installed to interconnect the lines when they were reactivated.

All of the vessels in the production battery are internally coated carbon steel and have not experienced any corrosion problems.

COSTS

Figure 9 compares the original commitment of funds for construction and operation of the Pilot with actual costs. Overall both capital and operating costs for the project amounted to less than 65% of those originally budgeted. Major reasons for the underruns have been because of fewer modifications to the Pilot than expected, excellent success entering abandoned cased wells, cost control techniques implemented, cost sharing with expansion patterns and lower than predicted inflation. The partners had originally committed to operating the Pilot even if there was no revenue. Figure 9 illustrates that the Pilot was completed for a net cost of less than 20% of the original commitment.

Despite the lower than expected mobile oil production and the precipitous drop in oil prices in 1986, the Pilot was able to recover a significant percentage of total costs from oil sales.

Since the start of our operation approximately 52.5% of field operating costs have gone to purchase and inject carbon dioxide, 4.5% to recycle produced gas, 26.5% on wells and 16.5% for production treating and water injection. The recycle of produced gas has been economical and has cost

us less than $4.00/Mg ($0.20/MSCF) in operating repair and maintenance costs. This permits us to inject higher volumes of carbon dioxide to recover additional oil.

Commercial potential. In order to put carbon dioxide flooding potential in perspective, a possible development of several light gravity oil fields in central Alberta using relatively pure carbon dioxide available within reasonable pipeline distance has been investigated. This development could only replace about one half of a typical small, 1600 m^3 (10,000 BOPD), in-situ oil sands project. Figure 10 shows the similarity of oil production profiles of the CO_2 floods and 50% of a combined cyclic and steam drive in-situ project. Capital and operating costs for the CO_2 and in-situ project are comparable in magnitude and timing as shown on Figure 11. The economics of enhanced oil recovery using carbon dioxide are better than the in-situ project primarily because of oil price differential, Figure 12. If a major source of economical carbon dioxide were available there is significant additional oil recovery potential in Alberta.

An environmental advantage is that even the small development contemplated above would store about 7.2 Tg (135 BCF) of CO_2 currently vented to the atmosphere. This accounts for some 40% of the total CO_2 released when the oil from these projects is utilized. To date the Joffre project has stored over 200 Gg (4 BCF) of carbon dioxide that would have otherwise been vented.

CONCLUSIONS

1. Carbon dioxide is an effective means of recovering tertiary oil from the Joffre Viking Oil Field. Recovery and CO_2 utilization are among the best reported in the literature and significantly better than the average projects reported.
2. Further development of numerical simulation techniques are required to adequately simulate performance of CO_2 miscible flooding without history matching the model to actual field performances.
3. A complete understanding of the geology in a field and its interaction on reservoir performance is critical to successful implementation of a miscible flood. Careful monitoring of performance to identify deviations from predictions and allow remedial action is essential.
4. Initial response indicates that simultaneous carbon dioxide and water injection is preferable to WAG or continuous CO_2 injection. Mobility control using foam generated by a surfactant has the potential to further improve recovery in carbon dioxide miscible floods. Injection techniques will have to be developed or alternate foams used that will propagate better in the reservoir.
5. With reasonable royalty regimes, an economical supply cost for carbon dioxide, and careful design and operation of projects miscible carbon dioxide flooding can recover additional reserves of light crude oil.
6. The Joffre Viking flood is environmentally attractive since it stores significant volumes of CO_2 which would otherwise be vented to the atmosphere, all produced water is reinjected, well spacing is large minimizing surface disturbance and the reuse of old wellbores reduces drilling requirements.
7. Carbon dioxide sources in Alberta suitable for miscible use without expensive processing are limited. In order for carbon dioxide miscible flooding to significantly contribute to arresting the decline in light oil production new technology will have to be developed to recover substantial volumes of CO_2 from low purity sources currently vented at an economical price.

ACKNOWLEDGMENTS

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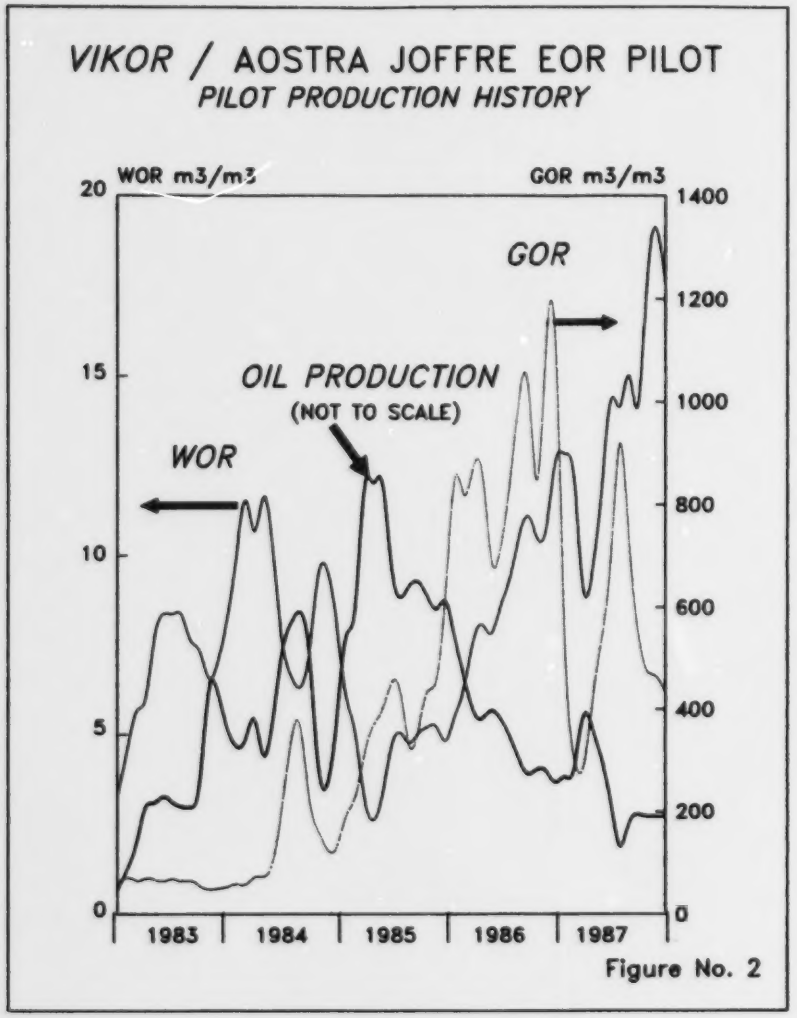
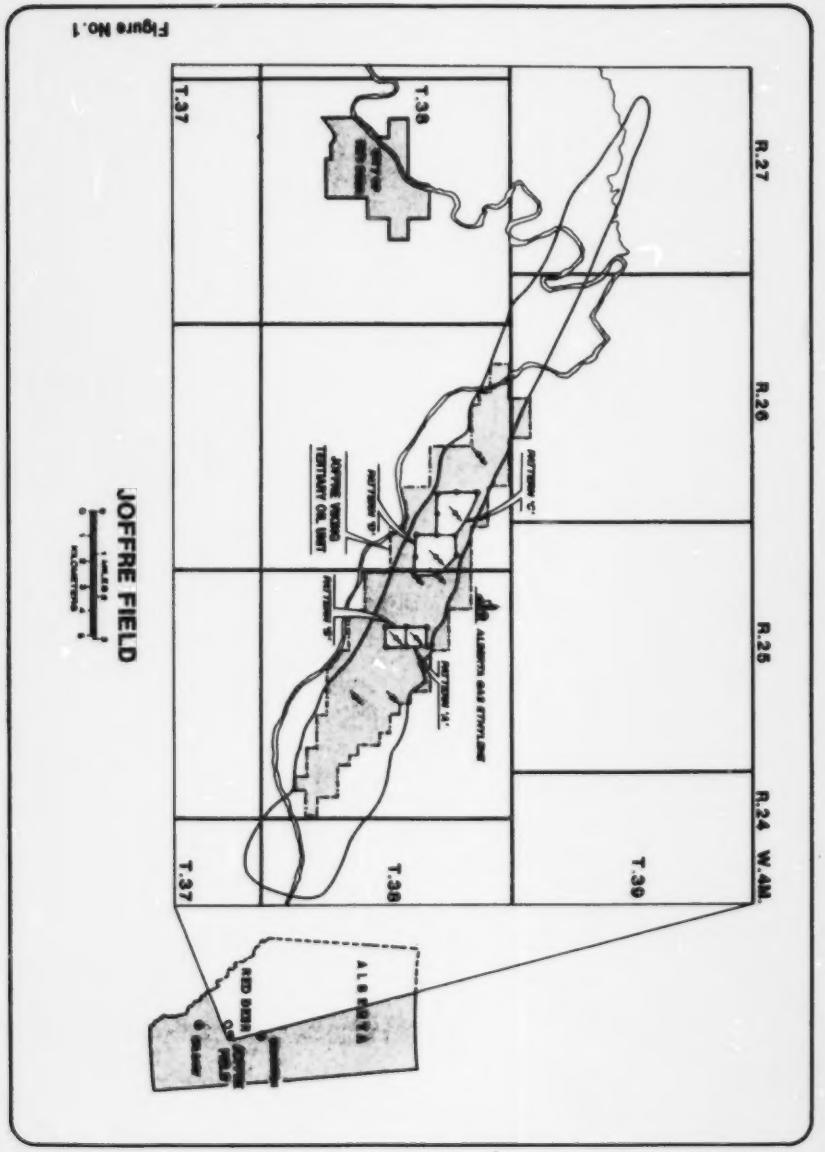


Figure No. 2

Figure No. 1



VIKOR / AOSTRA JOFFRE EOR PILOT

OIL RECOVERY – THOUSANDS CUBIC METRES

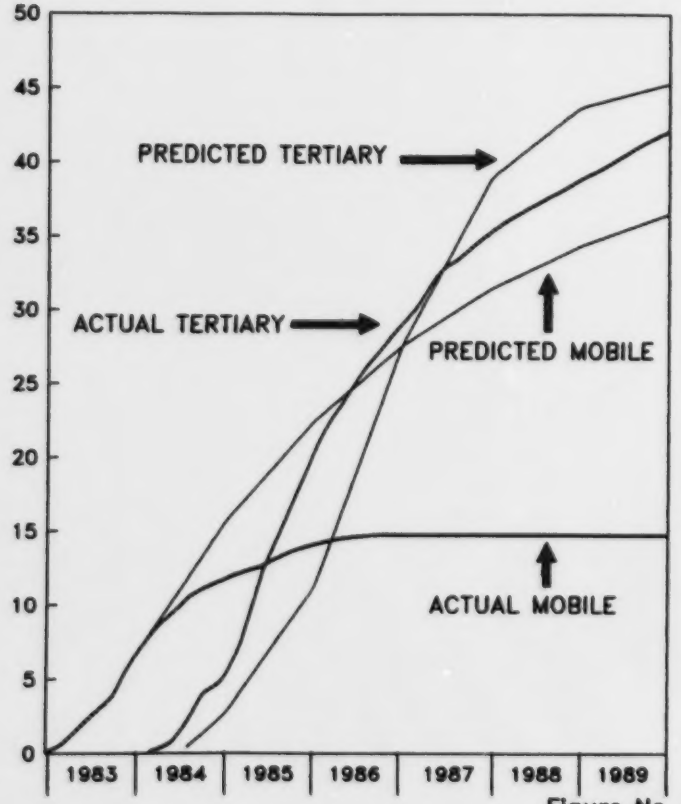


Figure No. 3

VIKOR / AOSTRA JOFFRE EOR PILOT

COMPARISON TO USA CO2 MISCIBLE PROJECTS

			21 USA PROJECTS		
		JOFFRE	AVG	MIN	MAX
DEPTH	metre	1524	1836	594	3962
NET PAY	metre	3.0	22.9	4.6	56.7
TEMPERATURE	deg C	56	57	28	120
PERMEABILITY	md	500	90	3	1200
POROSITY	%	13.0	15.9	9.0	26.4
OIL GRAVITY	kg/m3	813	840	793	882
VISCOSITY	mPa.s	1.0	1.3	0.3	6.0
OIL RECOVERY	% OOIP	20.0	12.9	7.1	22.0
CO2 INJECTED	% HCPV	43	40	19	160
GROSS CO2	Mg/m3	1.6	4.0	2.1	8.9

Figure No. 4

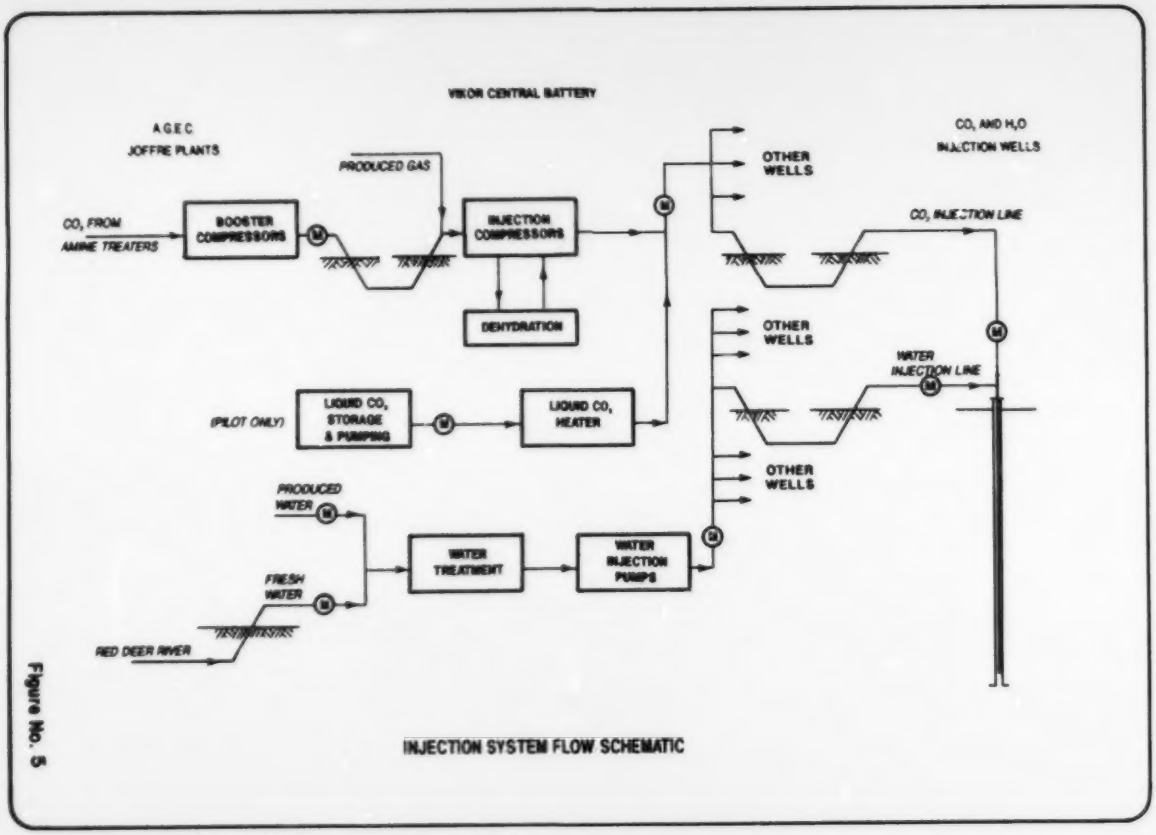
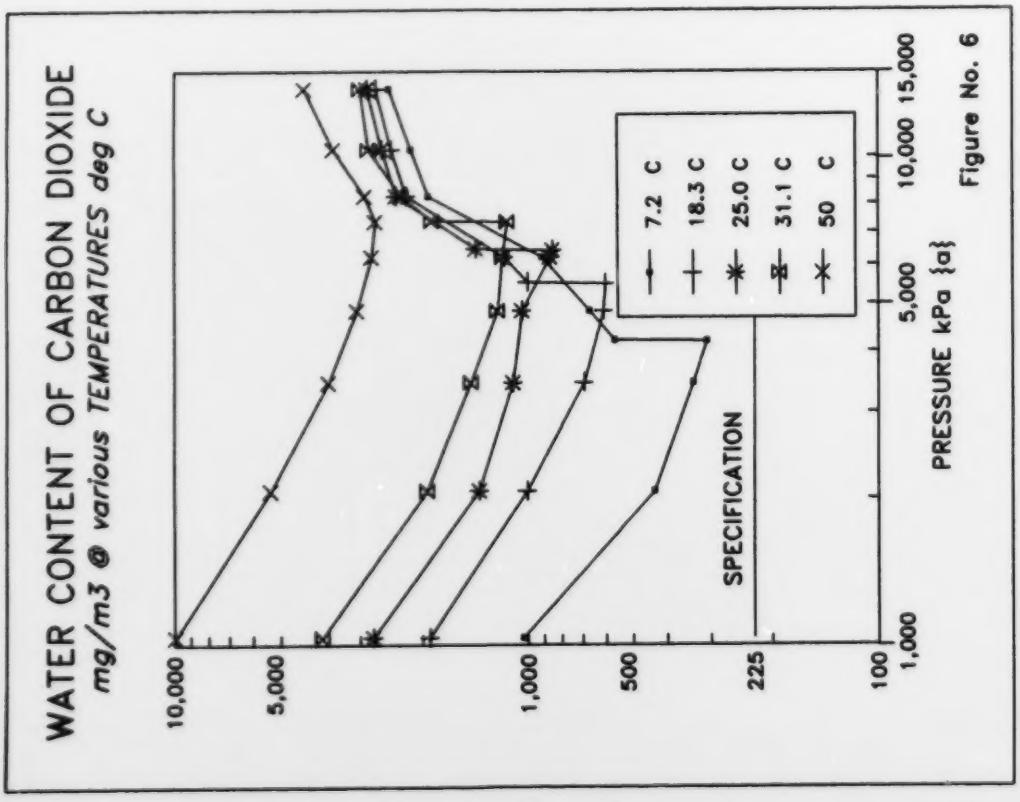


Figure No. 5

INJECTION SYSTEM FLOW SCHEMATIC



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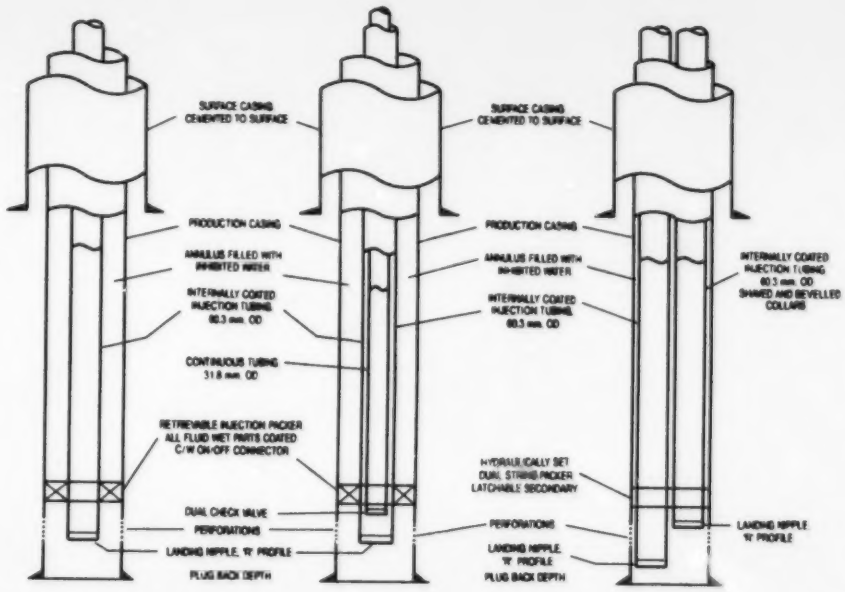

SURFACE CASING CEMENTED TO SURFACE
PRODUCTION CASING
ANNULUS FILLED WITH INHIBITED WATER
INTERNALLY COATED INJECTION TUBING 88.3 mm OD
CONTINUOUS TUBING 31.8 mm OD
RETRIEVABLE INJECTION PACKER ALL FLUID WET PARTS COATED C/W ON-OFF CONNECTOR
DUAL CHECK VALVE
PERFORATIONS
LANDING NIPPLE, 'R' PROFILE
PLUG BACK DEPTH
SURFACE CASING CEMENTED TO SURFACE
PRODUCTION CASING
ANNULUS FILLED WITH INHIBITED WATER
INTERNALLY COATED INJECTION TUBING 88.3 mm OD
HYDRAULICALLY SET DUAL STRING PACKER LATCHABLE SECONDARY
PERFORATIONS
LANDING NIPPLE 'R' PROFILE
PLUG BACK DEPTH
INTERNALLY COATED INJECTION TUBING 88.3 mm OD SHAVED AND BEVELLED COLLARS
LANDING NIPPLE 'R' PROFILE

Figure No. 7

ALTERNATIVE CO_2/WATER INJECTION WELL COMPLETIONS

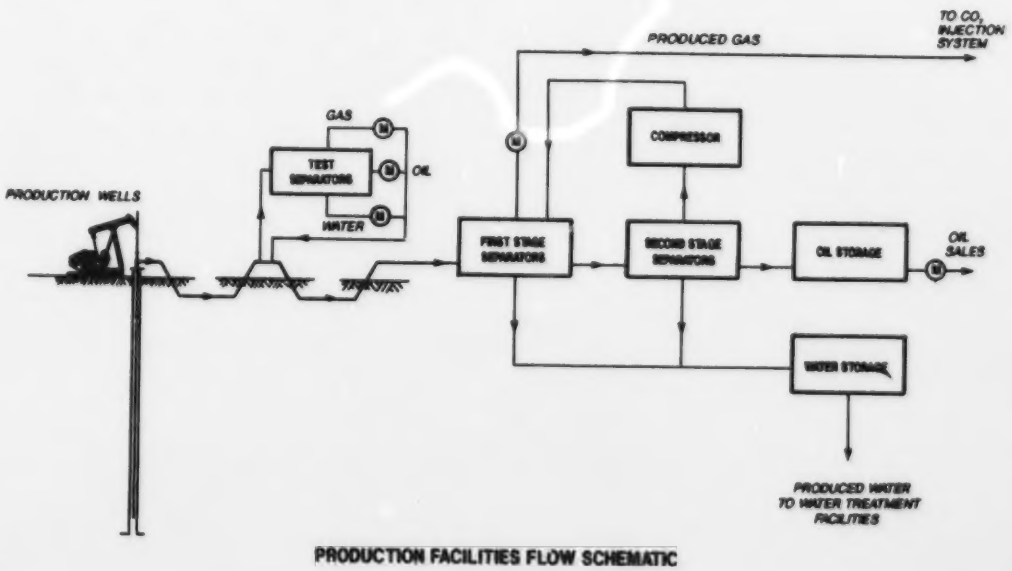
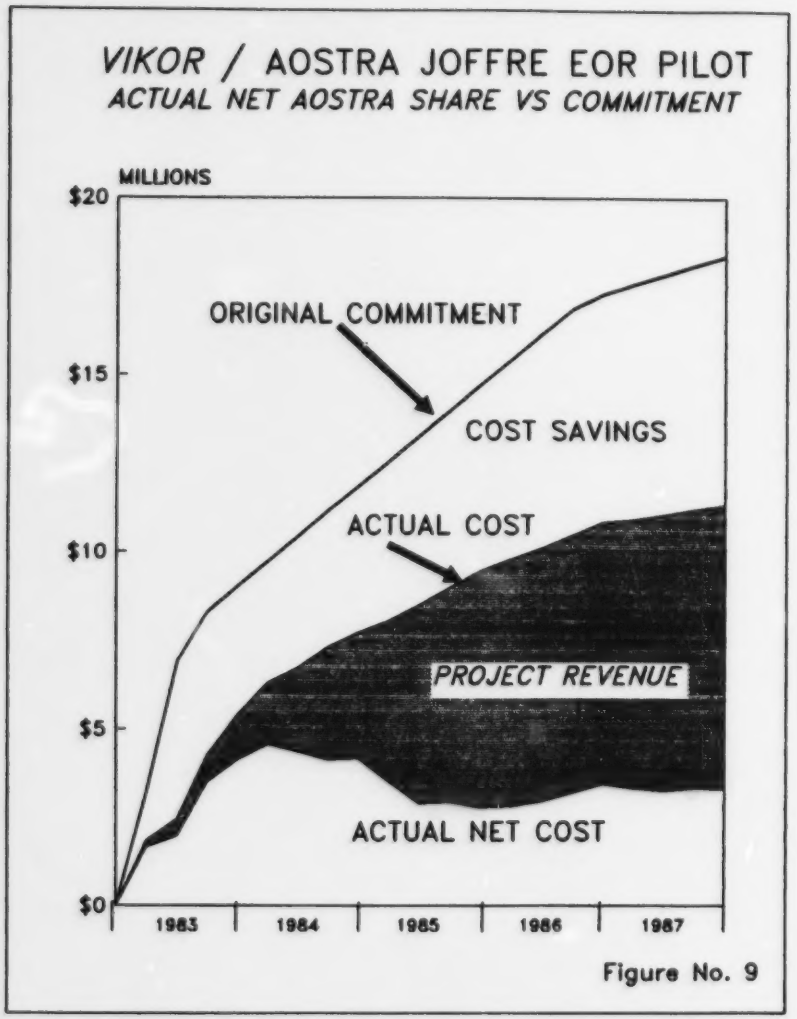


Figure No. 8

PRODUCTION FACILITIES FLOW SCHEMATIC



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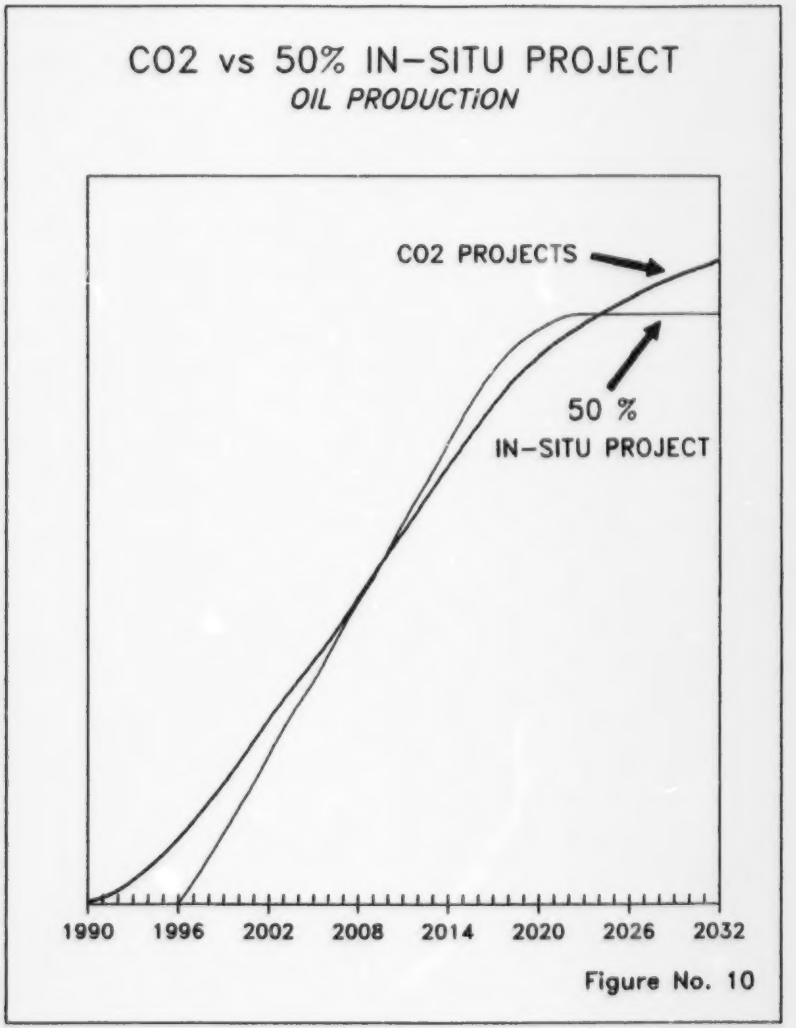

Figure No. 10

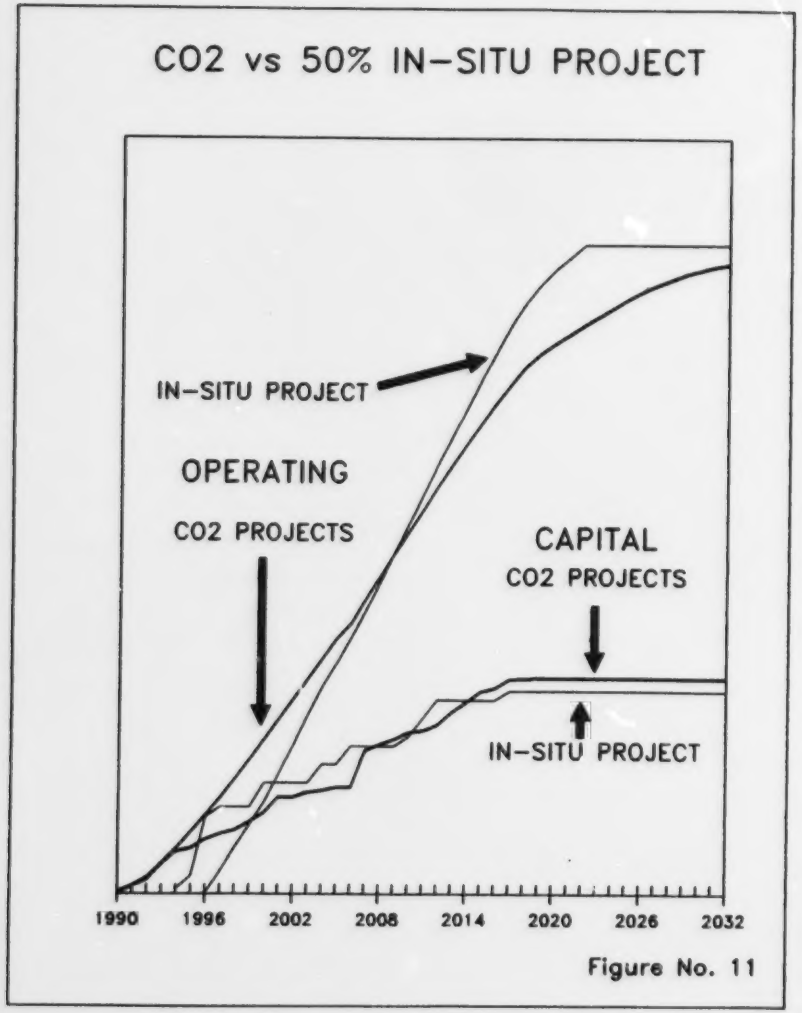

Figure No. 11

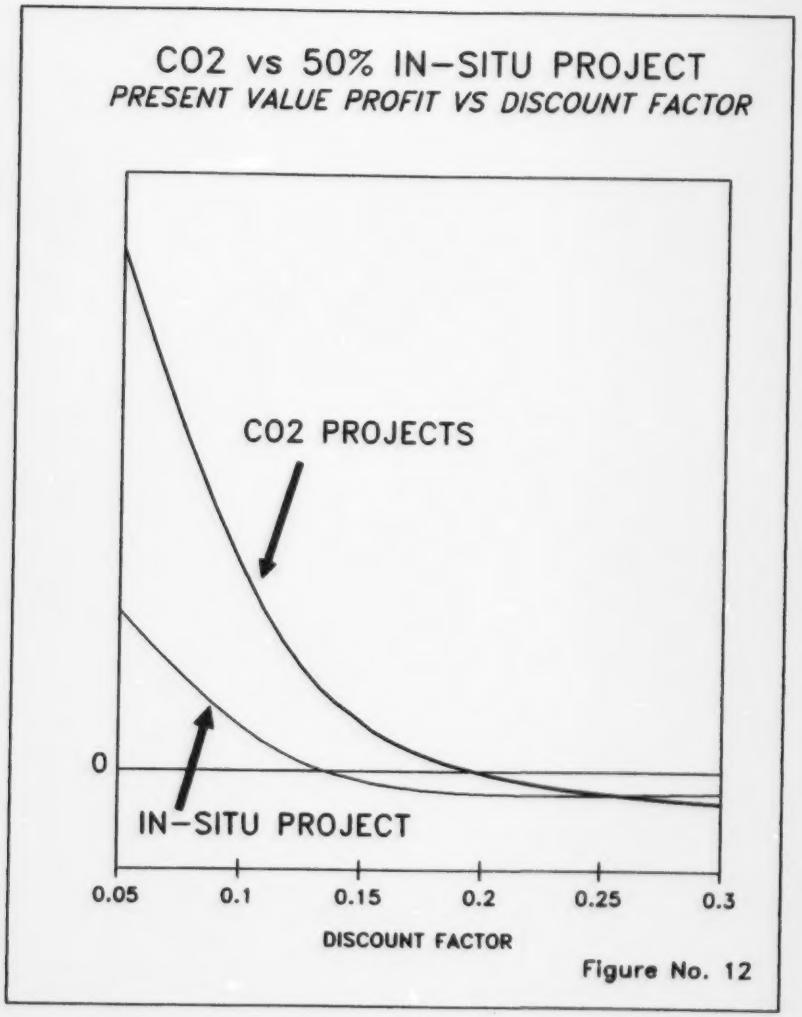

Figure No. 12

Bacterial To Control Conformance Of A Waterflood

Dr. J.W. Costerton, F. Cusack and H. Lappin-Scott, University of Calgary, and Mr. M.J. Chmilar and Dr. T.J. Cyr, AOSTRA

Abstract. Dr. J.W. Costerton and his associates, F. Cusack and H. Lappin-Scott, at the University of Calgary, have improved a microbial process whereby slime producing bacteria, isolated from produced oilfield waters, are used to plug high permeability water saturations in oil zones. By injecting starved bacterial cells, known as ultramicrobacteria (UMB), reservoir penetration into the desired region is enhanced and the bioplug created, following nutrient stimulation, is more extensive than that achieved when the larger vegetative cells are injected. AOSTRA has supported laboratory development of the concept towards a field application process. The Alberta Research Council and the Petroleum Recovery Institute have conducted a number of experiments which confirm the applicability of the technique in petroleum reservoir situations. Results suggest that water coning may be reduced by a well stimulation process and that the sweep profiles of water floods may be improved. Screening experiments have been developed to tailor the field process to specific reservoir characteristics. A field trial in which UMB and nutrient stimulation will be applied to limit further water influx, in a water coned well, is slated for this spring. Successful field trial results, anticipated within a short term, will foster development of a water flooding process application.

BACKGROUND

More than 50% of Alberta's light oils are produced by 'waterflooding'. The method is an old one. Clean water is injected at one or more wells to push the oil through the reservoir to nearby production wells where the oil is pumped to the surface.

Experience shows that the water eventually manages to find a small path or channel to a producing well thus bypassing a significant portion of the reservoir. Typically, the oil is much more viscous than the water. In such a case the amount of water produced each day soon much exceeds the amount of oil produced and the cost of pumping a unit volume of oil becomes too high. There is little that the operator can do to remedy the situation but shut in the well and drill another.

Recently, we observed that some bacteria may be mixed with the injected water to plug these channels and divert the waterflood to another portion of the reservoir which has not been waterflooded. Bacterial species and conditions for their growth were selected that would optimally place the plug in the reservoir.

Some bacteria, such as Pseudomonas, which is found everywhere in the soil, may become very small when starved. Their size is reduced to much less than one micron and hence they may be called 'ultramicrobacteria' or umb.

These umb possess special characteristics: they pass through small pores more easily than the healthy bacteria, they are less likely to adhere to surfaces, and when supplied with an appropriate nutrient they do not begin to grow until a predictable time has elapsed. This period may be selected by the choice of nutrient and may be one or two months. As umb, the bacteria are now small enough to easily permeate through the reservoir along the same path taken by the waterflood described above. There, after the predetermined time has passed, the bacteria adapt to the nutrients, adhere to the sands in the reservoir and begin to grow. As they grow, they produce an exopolysaccharide slime that fills the pores and inhibits further passage of water along this channel.

A subsequent waterflood therefore must find another path to reach the producing well. The effect is that the amount of oil produced suddenly increases and the amount of water produced decreases.

This method of employing umb has been tested at the Alberta Research Council and the Petroleum Recovery Institute. The results are encouraging. Here we describe umb and report the results and our conclusions.

ULTRAMICROBACTERIA

Bacterial cells have a very pronounced tendency to adhere to surfaces and to form adherent biofilms. Thus, even when bacterial cells of 1 μm diameter are injected into >20 μm spaces within particulate matrices, the bacteria tend to adhere strongly to nearest available surfaces to form a very shallow 'skin' plug (Shaw et al. 1985). Such a 'skin' plug may extend only a few centimeters beyond the wellbore and surfaces of hydraulic fractures extending therefrom. Such a model may be used to explain the occasional success (Jack, 1985; Lazar, 1985; Hower, 1957; Garland, 1966; Gaucher, 1960) and the many difficulties reported for bacterial floods.

Recognizing that 'skin' plugs are ineffective in diverting waterfloods from channels to conform to the reservoir, we sought a means of placing bacteria deeply in waterflood channels at predetermined distances in the reservoir. This required that the bacteria exist in two forms; one nonadhering and of diameter less than 0.3 μm, and another that grows rapidly in size and number and generates slime to plug interstices and pores. Moreover, a means to effect the transition from one form to the other was required.

Microbial Ecology studies of the abyssal ocean depths had produced an enigma in that direct examination of water recovered from these depths showed an almost complete absence of bacterial cells, when examined by conventional light microscopy, but was found to contain more than 1 million cells per ml when supplied with a sterile glucose solution. R.Y. Morita (Oregon State University) solved this enigma when he discovered (Morita et al., 1982) that most species of marine bacteria continue to reproduce when they encounter the very low nutrient conditions of the abyssal zone even though de facto starvation precludes any increase in cell mass. This phenomenon, which is now known as the starvation survival strategy, is very common amongst bacterial species and results in the formation of reduced dimension (ca 0.3 μm) ultramicrobacteria (umb) in place of the larger (ca 1.0 μm) vegetative cells seen in nutrient sufficient ecosystems. The restricted internal volume of these umb is just sufficient to contain their genetric apparatus and a few enzymes for endogenous metabolic activities, and they can remain viable for at least 5 years in this state of suspended animation. Starvation conditions severely limit the production of extracellular polysaccharides so that the umb are not notably adherent (except to hydrophobic surfaces?) When umb encounter nutrient rich conditions their metabolic machinery is rapidly induced and umb of most species return to full size (ca 1.0 mm) and full expolysaccharide production in less than one hour.

Because starvation survival to form umb is a universal bacterial strategy, we would expect to find these very small cells in any ecosystem in which nutrients are scant. These umb have now been detected in freshwater lakes (Martin et al., 1984; MacDonnell et al., 1982), in shallow groundwater (Gray, 1976; Munbaeva et al., 1975; White et al., 1983), and in deep (+1000 m) ground waters (Raiders et al., 1988), and in each case they have been shown to resuscitate rapidly when nutrients are added. We can therefore presume that umb exist in all aquatic ecosystems that are physically permissive in terms of temperature, salinity, pressure, and solution chemistry and that a very large variety of bacterial species will be detected when nutrients are added to these systems. The mats of vegetative cells of methane-oxidizing bacteria that develop around the 'black smokers' on the ocean floor provide a illustrative example?

ULTRAMICROBACTERIA IN CONFORMANCE CONTROL

Because we had resolved to use suspensions of single species of native deep groundwater bacteria, we isolated the predominant bacteria from produced water from several oilfields and starved dozens of isolates that did not produce H_2S. Approximately 60% of these bacterial isolates produced umb in response to starvation, and approximately half of these umb-producing organisms produced clear suspensions of these very small cells (MacLeod et al.). Typically, cultures that were grown to a cell density of 1×10^9 cells/ml would respond to starvation by producing over 5×10^{10} umb/ml after two to four weeks of starvation. These suspensions of umb are stable for years, without refrigeration, and are diluted 1,000-1,500 fold to give the 1×10^6 umb/ml suspensions that have been used in the experimental selective plugging experiments (Lappin-Scott et al., 1988).

Early experiments in which umb were injected into 10 cm Ottawa sand cores indicated that these very small (ca 0.3 μm) dormant cells easily penetrated sandstone with permeabilities greater than 180 millidarcies without skin plugging at the injection face. Direct examination of sections of these umb/flooded cores, by scanning electron microscopy (SEM), showed that these very small cells were evenly distributed throughout the porous sandstone (Figure 1). The umb front appeared to penetrate these cores readily and considerable numbers of these minute organisms were found in the first volumes of effluent. When the umb within these cores were resuscitated using rich nutrient media (Brain Heat Infusion broth), the rapid growth of vegetative bacteria near the injection face limited the penetration of nutrients into the core and an uneven plugging was observed. However, when the umb were resuscitated by stimulation with a more refractory nutrient (citrate) that required some

adaptation of bacterial metabolism before it could induce the formation of exopolysaccharide-producing enzymes, all of the pore spaces of the cores were evenly filled with bacterial cells and slime (Figure 2.). A typical response is shown in Figure 3. At this point in the development of the umb technology AOSTRA decided to file for patent protection, with emphasis on the choice of specific nutrients for the optimal resuscitation of these starved cells, and the resultant patent (US #4,800,959) was issued in 1989.

It was decided that the umb selective plugging technology should be further demonstrated in the 3-dimensional physical simulators at the Alberta Research Council. The very experienced team of Surindar Singh and Dzung Nugyen were coopted to provide engineering expertise. A 45 cm simulator was packed with Ottawa sand (permeability 3.8 D) and sampling probes were located at various distances from the single injection point (Figure 4). The first simulator experiment showed that umb penetrate the sand pack with great facility and umb were detected at each sampling probe shortly after the onset of injection. When nutrient was injected into the umb-flooded sand pack it stimulated the resuscitation of the umb very evenly and, at the termination of the flooding experiment, direct sampling of the sandpack at several locations showed the presence of vegetative bacterial cells and large amounts of the viscous exopolysaccharides produced by these organisms. The sandpack had been plugged by the nutrient stimulated resuscitation of these starved bacterial cells., throughout the 45 cm radial simulator. (RPF Singh et al., 1988)

For effective conformance control the plugging bacteria should preferentially enter and plug the high permeability zones where water invasions occurs.. Raiders et al., (1989) had shown that dormant bacterial spores plugged the more permeable slab when two sandstone slabs were closely juxtaposed and flooded with spores followed by resuscitating nutrients. A second consolidated 45 cm sandpack (3.8D) was constructed surrounding a sandstone core having 400 mD permeability (Figure 5). When this apparatus was flooded with umb and nutrients it was found that the umb had entered both the permeable sandpack and the less permeable sandstone core but that preferential plugging had occurred in the more permeable zone. To this point it was shown that umb could readily penetrate rock matrices greater than 180 mD in permeability, that these umb would resuscitate and form vegetative cells when stimulated with suitable nutrients, and that the more permeable zones could be selectively plugged using this technology.

It has been well documented that deep groundwater bacteria grow well at high pressures, at high salinity, and in the presence of reservoir rock (McKinley et al 1988) but it was considered prudent to demonstrate that the umb that were to be used in field experiments would actually resuscitate in response to nutrient stimulation under downhole reservoir conditions. Accordingly AOSTRA sponsored several experiments at the Petroleum Recovery Institute (PRI - Calgary) in which umb were suspended in produced reservoir brine, in the presence of crushed reservoir rock, and produced oil and were stimulated by the addition of a nutrient (citrate) in a sealed vessel pressurized with gas. The umb formed vegetative cells and produced large amounts of exopolysaccharide under these static simulated reservoir conditions. In collaboration with PRI's Jerry Novosad, a field core was saturated with produced oil from the same field and then waterflooded to residual oil saturation. This 'watered out' core was then flooded with one pore volume of 10^6 umb/ml followed by nutrient (citrate) and when injection was periodically resumed, after brief incubation periods, residual oil was displaced. These tests at PRI have established that umb resuscitate satisfactorily under reservoir conditions and that the resultant plugging can improve oil recovery.

ULTRAMICROBACTERIA IN FIELD APPLICATIONS

Experimental results from the work conducted at the Alberta Research Council and the Petroleum Recovery Institute indicate that this umb technology may be successfully applied to production wells, to remediate water coning, or to injection wells, to improve sweep profiles in a waterflood.

An initial application to a stimulation process for water coned wells has been devised. The objective of a field test, involving the injection of a umb suspension followed by a nutrient solution at the water-oil interface, is to generate a mat of vegetative bacteria and exopolysaccharide across this horizon. Based upon the coned area, the mat should extend at least 10 meters radially around the wellbore to be effective in restricting water influx. The observed ability of the umb to readily penetrate sandstone matrices suggests that this goal is easily attainable. The volumes of the umb and nutrient required are readily transportable in a concentrated form and would be diluted with produced water, at the wellsite, for injection. The creation of a uniform mat, after a brief incubation period, should be reflected in the near term improvement in the producing water:oil ratio.

The field test would also permit an evaluation of the longevity of the mat, in terms of the duration of inhibited water production, and the prospect of enhancing or restoring the plugging effect by subsequent injection of nutrients.

Further development of the umb technology, towards enhancing waterflood oil recovery will be pursued once the initial application to water coned wells has shown positive responses. Waterflood conformance control by umb injection and in situ

production may be the best application of this technology, however it will be a secondary development thrust because longer times are required to elicit results.

SUMMARY

The use of bacteria, as umb, to selectively plug high permeability, water saturated channels in oil reservoirs has been vindicated. Where vegetative bacterial cells have often failed to penetrate porous media, deeply enough to give a useful viscous plug, very small non-adherent umb, derived from these microbes by starvation, have been shown to easily penetrate sandstones and respond to nutrient stimulation by creating extensive and effective plugs. This technology has been demonstrated in simulated reservoir conditions and offers to recover reidual oil from 'watered-out' reservoir sands. The fundamental questions concerning the efficacy of this technology have been satisfactorily addressed in the laboratory and further development and refinement await implementation in field trials. Successful field test results will usher in a promising new tool for the control of excessive, oil field water production problems.

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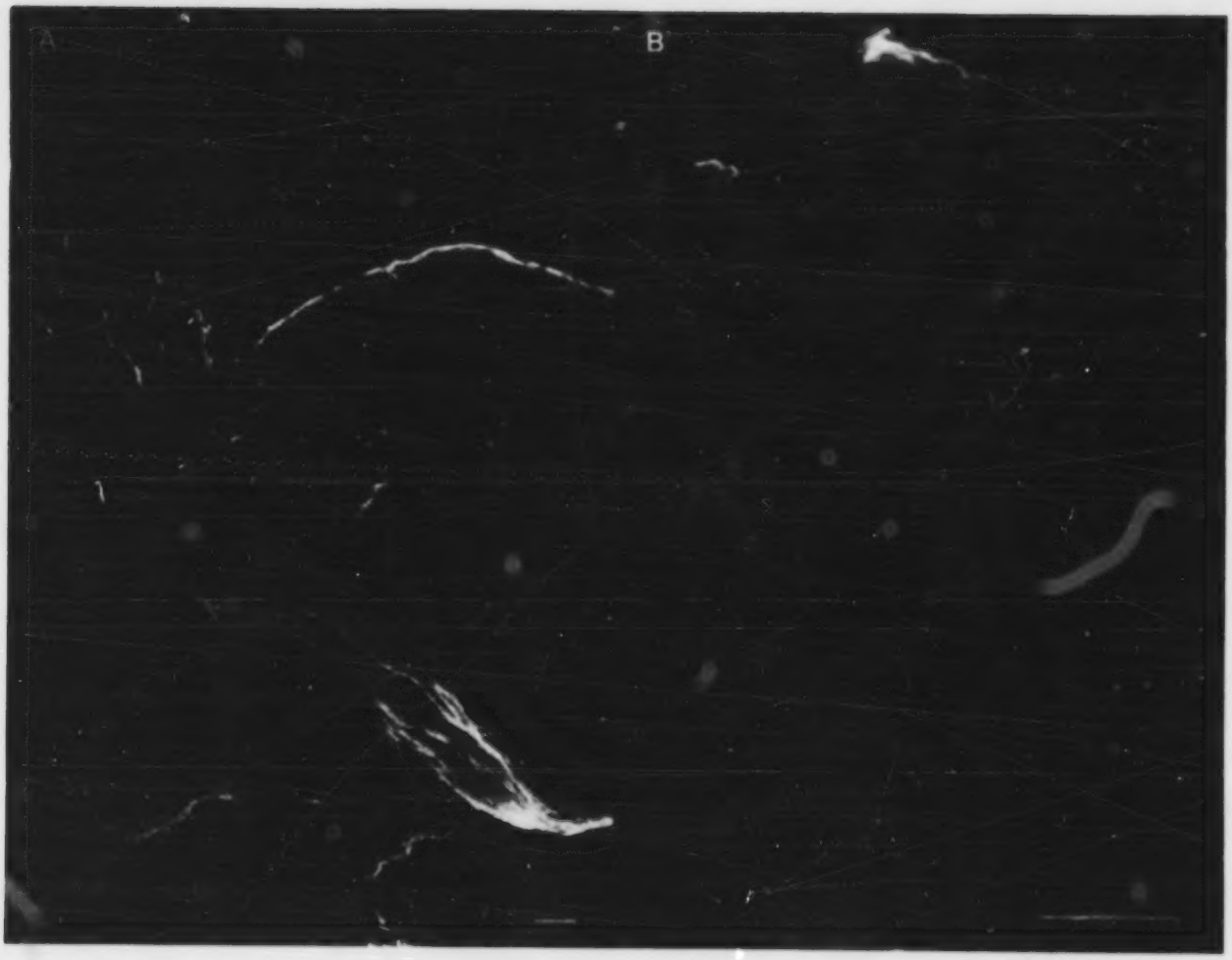

Figure 1. Scanning electron microscopy of (A) lean sandstone and (B) sandstone uniformly covered by umb. Scale bar represents 5.0 umb. Scale bar represents 5.0 μm.

Figure 2. Scanning electron microscopy of resuscitated umb and its sticky polymer in four sand samples. all sections are covered with exopolysaccharide slime. Scale bar represents 5.0 μm.

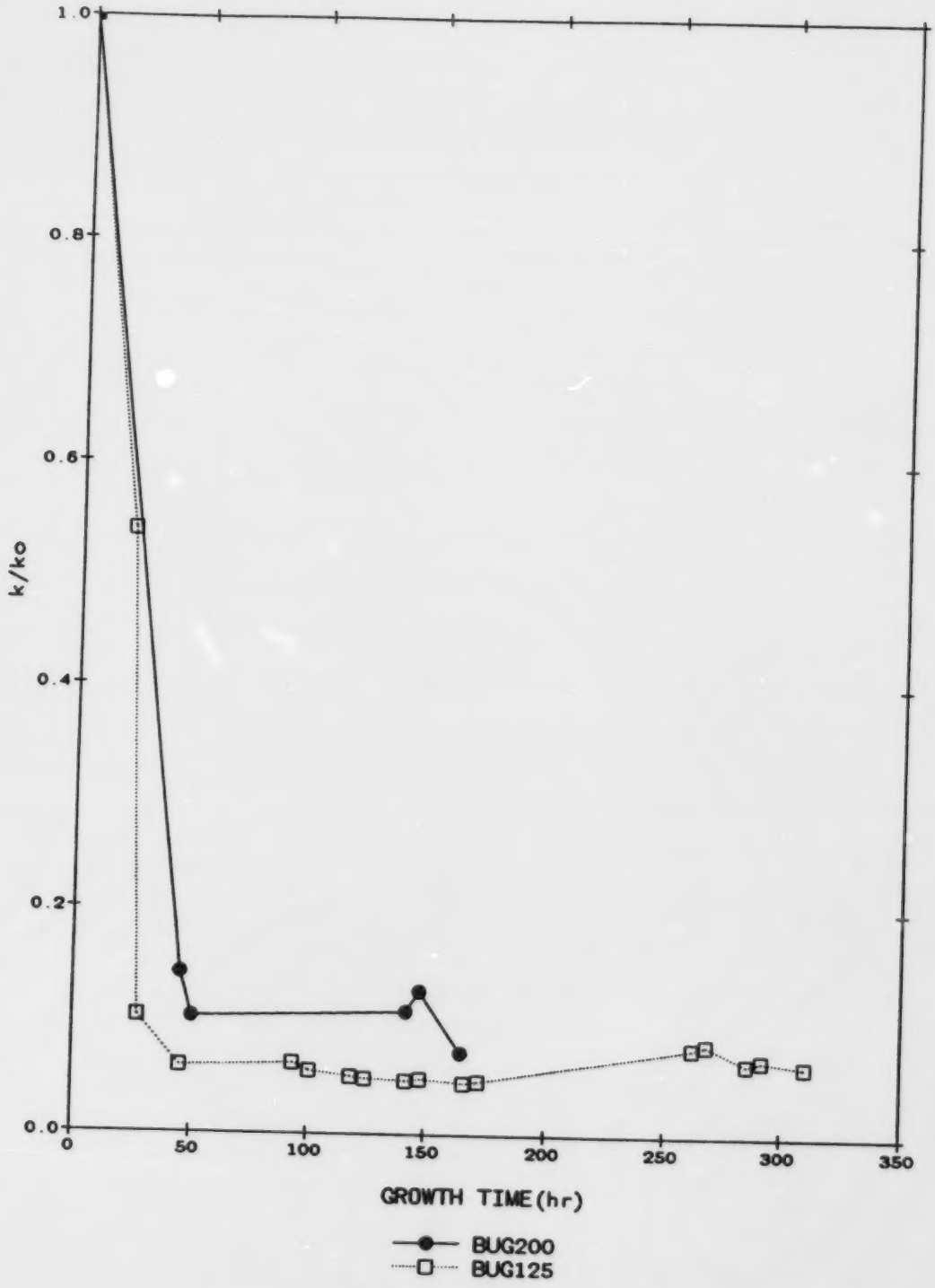

Figure 3. Permeability reduction with time following nutrient stiumiation of umb in 10 cm sandpacked core.

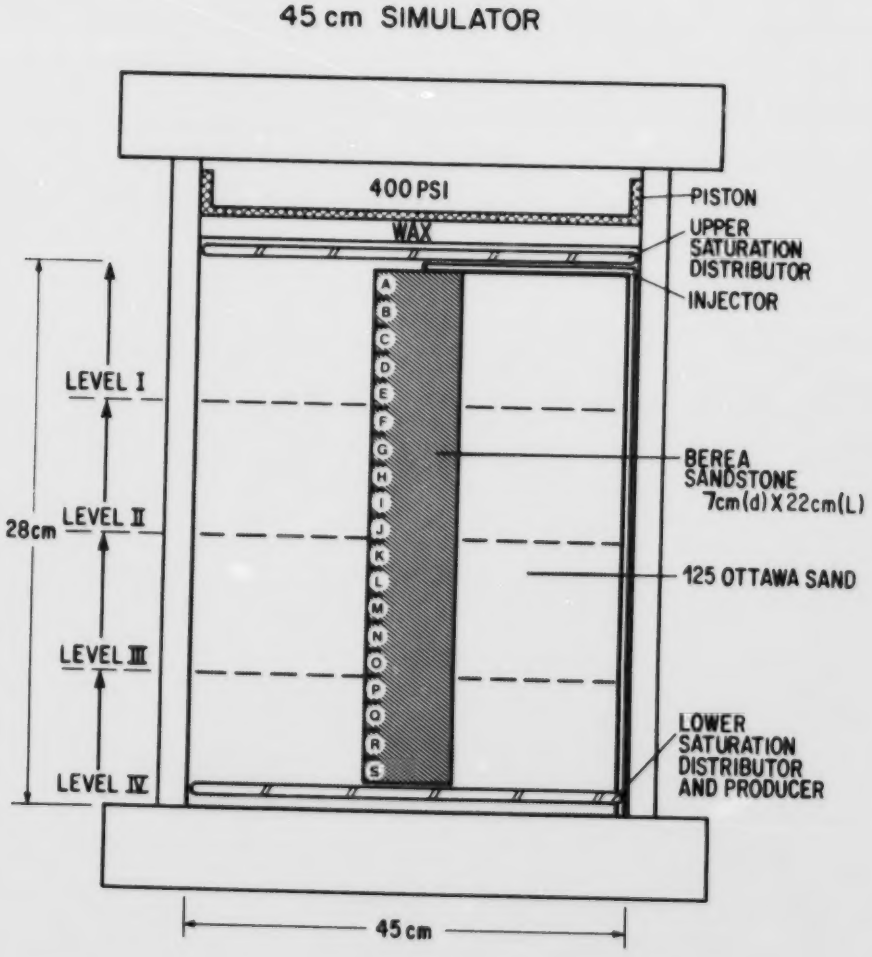

Figure 4. A schematic diagram of the 45 cm simulator showing sample probe locations.

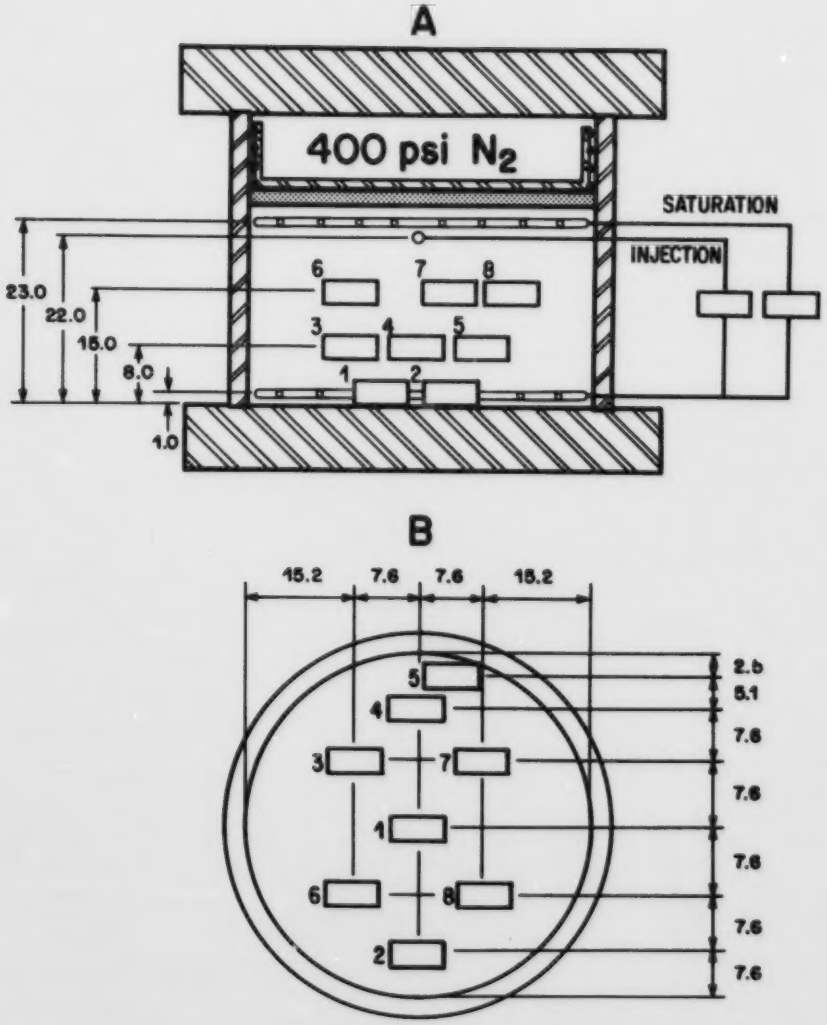

Figure 5. A diagramatic representation of the heterogeneous test bed in the 45 cm simulator. The sandstone core is embedded in sand.

Environmental Aspects Of In Situ Recovery Of Oil Sands And Heavy Oil

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Abstract. Alberta holds over 40% of the reported oil sands bitumen in the world and has, as well, substantial heavy oil deposits. As conventional oil reserves decline, oil sands and heavy oil represent the future of the oil industry in Alberta. Over 90% of the bitumen is deeply buried and will need to be recovered by in situ production methods. The heavy oil deposits will require in situ secondary recovery methods to improve the ultimate recovery of oil in place.

There are several environmental aspects of bitumen and heavy oil production by in situ methods which are encountered, in addition to those anticipated for conventional oil production. An overview of the environmental aspects of in situ recovery for oil sands and heavy oil is provided, along with the environmental safeguards currently in practice.

Oil sands and heavy oil production is anticipated to grow in the future. The increased application of in situ recovery methods is anticipated to have a relatively minor environmental impact. The future of in situ oil sands and heavy oil development is discussed from an environmental point of view.

INTRODUCTION

Throughout the world there are very large deposits of oil sands and heavy oil which will, in the future, be increasingly produced by in situ recovery methods. Although there appears to be abundant supplies of low-cost light oil at this time, it must be recognized that currently over 90 percent of the world demand for petroleum is supplied by light and medium oil while these crude oils account for less than 25 percent of the remaining world petroleum resources. As light oil reserves are depleted and/or prices rise, the production of bitumen from oil sands will assume increasing importance.

The Free-World oil consumption in 1986 was in the order of 7.5 million cubic metres a day, with the U.S.A. consuming approximately 2.7 million cubic metres/day. About 50 percent of the U.S.A. consumption of oil is currently imported, with about 13 percent of that amount, as crude and oil products, being supplied by Canada. The National Energy Board has estimated that conventional oil production in Canada will decline by close to 80,000 cubic metres (500,000 barrels) per day over the next decade. Increasingly the vast Alberta oil sands bitumen reserves will be considered to fill the future shortfalls in energy availability. Over 90 percent of the total in place bitumen in Alberta is too deeply buried to be recovered by commercial surface mining methods, and consequently in situ recovery methods will be necessary. The recovery of heavy oil by primary production is limited to a small percentage of the oil in place and thermal in situ recovery methods will be required in many cases to improve the ultimate oil recovery. Conventional light and medium oil production in Alberta has declined from a peak of about 223,000 cubic metres/day in 1973 to approximately 135,000 cubic metres/day in 1988/89. Bitumen and synthetic oil now make up about 20% of Canada's total production of crude oil. Enhanced oil recovery has also grown and now provides about 16,000 cubic metres/day.

In situ methods to recover bitumen and heavy oil will increase in Alberta in order to supply the requirements for petroleum not filled by the declining conventional production. A gradual switch from conventional oil production to increased in situ recovery of oil sands and heavy oil will provide a change in the types of operations involved. The increased application of in situ recovery methods is anticipated to have a relatively minor environmental impact. The environmental aspects of in situ recovery of oil sands and heavy oil are outlined in this paper.

OIL SANDS RESERVES IN ALBERTA

The total reserves of bitumen is vast and conservatively estimated at over 635 billion cubic metres of oil in place world-wide. In Alberta there is about 270 billion cubic metres1 of bitumen in place in the oil sands and carbonate formations plus about one billion cubic metres of heavy oil. Thus Alberta holds over 40% of the reported bitumen in the world. In contrast to the vast bitumen reserves, Canada has only 1.1% of the world's light and medium crude oils. The world wide distribution of oil sands deposits is shown in Figure 1.

In Alberta there are four major oil sands deposits plus the Grosmont Carbonate formation which contains large amounts of bitumen. These are shown in Figure 2. The four major oil sands deposits cover an area of about 4.5 million hectares in the northern half of the province. About 8 percent of the total oil sands in Alberta are covered by less than 50 metres of overburden and are considered economically suitable for surface mining. The surface mineable reserves are all located within the Athabasca deposit. The amount of in place bitumen, which has more than 170 metres of overburden and can be potentially recovered by in situ methods, is 10 times the surface mineable reserves; 78 percent of the deposit. The remaining 14 percent are overlain by 50-170 metres of overburden and it is uncertain, at this time, whether the heavy oil in these sands will be recovered by some form of mining or by novel in situ recovery methods. The consideration of the depth of the deposits points out the need for development of in situ recovery techniques, in order to tap the majority of the reserves in the Alberta oil sands.

Plots of viscosity versus temperature for oil including the initial reservoir temperature from each of the oil sands and several typical heavy oil deposits are shown on Figure 3. Although the oil viscosities are very high at initial reservoir conditions, the curves illustrate the significant reduction with increasing temperature. This is the reason thermal in situ processes are fundamental in recovering this oil, particularly in the oil sands deposits. Experience is showing that a number of different recovery processes may be necessary to recover the majority of bitumen and heavy oil, and that combinations and innovative modification are often necessary to find a process which will work in specific locations.

COMMERCIAL BITUMEN PRODUCTION

Light oil production in Alberta appears to have peaked and bitumen production has been increasing with bitumen/synthetic oil now making up about 20 percent of Canada's total production of crude oil. About 43,000 cubic metres of bitumen/synthetic oil are produced daily and 15,000 cubic metres per day of that is produced by thermal in situ recovery. The remainder of the 43,000 cubic metres per day are produced by the surface mining of oil sand at the Syncrude and Suncor operations near Fort McMurray. The bulk of the thermal in situ production of bitumen comes from three commercial projects. The largest is the Esso Resources development at Cold Lake which produces about 13,000 cubic metres per day. It is interesting to note that a recent Esso annual report, indicated that over half of its Canada wide production came from bitumen and heavy oil sources. BP Canada and Petro-Canada jointly have a 1000 cubic metres/day development at Wolf Lake in the Cold Lake oil sands. Shell Canada's PREP project, in the Peace River oil sands, produces about 1600 cubic metres/day of bitumen. Alberta Oil Sands Technology and Research Authority (AOSTRA) was a 50% participant in the pilot plants that developed the technology used in Wolf Lake and Peace River operations, and is the owner of the technology being used at both sites. The Esso Cold Lake, Wolf Lake and Peace River PREP operations have plans for expansion of production. Indeed, with recent announcements, in situ bitumen production is on the verge of surpassing the current production levels of synthetic crude oil from the oil sands, although current oil prices have led to delays in implementation. As market conditions improve and new expanded projects come on stream, particularly commercial scale in situ recovery operations, these will be subject to Alberta regulatory review.

REGULATORY FRAMEWORK

The regulatory framework leading to approval of an in situ recovery scheme is reviewed to provide guidance in planning, and perspective on the extent and nature of the approval process in Alberta. This is not a detailed plan, but an overview of the major components leading to project approval.

Energy Resources Conservation Board Approval

Public Consultation. The regulatory process is made up of many components collectively aimed at gaining public and government acceptance of a development scheme. Public understanding and acceptance of a development proposal is vital to the success of an application, but the process of obtaining acceptance is not as well charted as the documentation of the formal application. Today the public demands a role, not only in reviewing a project, but shaping the project. Public consultation, and the proponent's response to the input from people in the project area, is as important to the approval of a project as the technical excellence of the application. The importance of community liaison and the involvement of people residing in the

area, at an early stage of project planning, cannot be over emphasized.

A very effective and advanced form of mediation and consultation has been developed in the Fort McMurray area in the past few years. The Syncrude Expansion Review Group (SERG) was formed in 1985 at the encouragement of the Chairman of the Energy Resources Conservation Board (ERCB) to bring all interested parties to the table to review the CAP Mine Application. The same group was assembled in 1987 to review Syncrude's Expansion Application. The mediation process was so successful in discussing and resolving environmental and community issues that neither application went to public hearings. This process has been initiated at an earlier stage with the OSLO Oil Sands Project; with the Application Review Team (ART) defines issues and plays a direct role in the environmental and socioeconomic impact assessments. The application review team includes the local Indian Band, the City of Fort McMurray, representatives from all government agencies, with a regulatory responsibility, and the applicant. The public consultation program for an in situ project is not likely to be as extensive as those mentioned above for major commercial mining projects, but the process of early involvement of the public most directly affected by the development is very important.

Formal Application. The major legislation guiding the formal regulatory approval of an in situ oil sands and heavy oil development is the Oil Sands Conservation Act and the Oil and Gas Conservation Act administered by the Alberta Energy Resources Conservation Board. The regulations to these acts spell out the information required in a filing for an approval of a development scheme. The application is divided into four components.

- The first component is an overview description of the project, including a statement of need, timing and location of the development.
- The second component of the Application includes the technical description of the project. Technical details include an estimate of crude bitumen in place, recovery process, field development plan, process facilities, material and energy balances, utilities and off site facilities.
- The third component is the Environmental Impact Assessment (EIA), which incorporates both the biophysical and the social impact assessment. An Historic Resources Impact Assessment (HRIA), as prescribed by The Alberta Historic Resources Act can be integrated in this step of the formal documentation for project approval.
- The fourth component of the ERCB Application contains economic information. Three major topics must be addressed: commercial viability, economic impact, and a cost-benefit analysis.

Alberta Environment Approvals

The Alberta Environment Department and the ERCB have coordinated their requirement for the preparation of the Environmental Impact Assessment, however, there are other major approvals required under legislation administered by the Alberta Environment Department.

Development and Reclamation Approval. Development and Reclamation approval, required under the Land Surface Conservation and Reclamation Act, is the next major step in the regulatory approval process. This requires the filing of a Development and Reclamation Plan (D & R Plan) which addresses the development plans in detail, including site development, details on drilling pad locations, flow lines, pipelines, roads, and all support facilities. In the case of an underground in situ development, mine development plans are required which identify the amount of excavated material, together with a discussion on the handling, disposal and reclamation of the material.

The D & R Plan must address the life expectancy of the project, conceptual decommissioning and all steps leading to reclamation and revegetation of the project area. The D & R Plan for commercial projects may include additional detail in the form of technical support documents. These documents address such subjects as; surface and groundwater hydrology, soil survey and other baseline biophysical data to be used in developing the end land use reclamation objective, and procedures to achieve the objective. The committee that reviews and approves the D & R Plan has representation from many departments of the Alberta Government, therefore, the Plan must meet the requirements of a broad range of interests and regulatory requirements.

Clean Air and Clean Water Approvals. The Alberta Clean Air Act and Clean Water Act are parallel in their requirements, though they differ in specific areas of regulation. The proponent must apply for and obtain a Permit to Construct the facilities under each of these Acts before construction of facilities can begin. These applications require engineering details and process flow diagrams. Upon completion of the facilities, an application must be submitted to obtain a License to Operate. The level of detail in this application is virtually an 'as-built' plan.

Forestry, Lands and Wildlife Approvals

The Alberta Forest Service, the Public Lands Division and the Fish and Wildlife Division play major

roles in the review and approval of the Environmental Impact Assessment and the Development and Reclamation Plan. On 'green area' lands, the Alberta Forest Service plays a key role in controlling and monitoring all surface activities such as drilling programs and road construction. Surface rights must be obtained from the Public Lands Division for work on all Crown Land.

MANAGEMENT AND OPERATING CHALLENGES

Surface Disturbance

One of the major environmental benefits of in situ recovery of oil sands and heavy oil is the limitation of ground surface disturbances which may result in limited disruption to biophysical resources. These include landforms, forests, soil, wildlife, fisheries and aquatic systems. Surface disturbance concerns are particularly evident in the development of the Athabasca deposit, where development to date has been limited to surface mineable projects. The opening of an oil sands surface mine, transport of oil sands to the extraction facility and the return of the clean sand to a tailings pond or mined out pit represents a major technical challenge in reconstruction and reclamation of the landscape. It also represents a significant cost in the order of $0.18 to $0.20 per cubic metre of bitumen produced. In situ extraction on the other hand represents less disturbance to the land surface, and the severity of the disturbance is similarly reduced to roads, pads, pipelines and other facilities which are relatively easy to reclaim. Land reclamation costs, therefore, are a relatively small component of the total environmental cost for in situ developments.

Surface disturbance is largely associated with the network of surface wells, flow lines and roads connecting these operations. Directional drilling from pads containing several wells contributes to the reduction of surface disturbance. Shaft and tunnel access for in situ operations such as AOSTRA's Underground Test Facility (UTF), further reduces the surface disturbance as the network of wells and most of the pipelines are contained underground. Horizontal wells, drilled from underground, access significantly more bitumen than conventional vertical wells drilled from surface. Haston et al.[2] report that a potential UTF Commercial scheme of 1600 cubic metres per day over a life of 16 years will employ 70 well pairs. A similar operation using vertical wells could drill between 600 and 800 wells for the same total production. Reduced surface area and complexity of surface activities reduces disturbance to wildlife and avoids many of the land use conflicts which occur between oil sands developments and traditional pursuits by native inhabitants of an area.

The surface areas utilized by comparable in situ recovery operations with vertical wells, cluster drilling[13,14] and shaft and tunnel access methods[2] are compared in Table 1. The shaft and tunnel reservoir access method utilizes the least surface area while the vertical well reservoir access method utilizes the most surface area.

Groundwater

Groundwater must be considered in the development of in situ recovery schemes for two main reasons. The first consideration is that groundwater aquifers may be the source of process water as in situ operations are often located away from adequate sources of surface water. Consequently, groundwater uses in heavy oil production, particularly in southern Alberta, can compete with other industrial or agricultural users.

The second consideration is the disposal of process affected water to deep aquifers which is a normal operating procedure. Hitchon and Bachu[3] point out that vertical fractures in the disturbed zone around the well, as well as openings in the casing cement, may result in potential upward migration of fluids around the wellbore. This work indicates the importance of proper installation and completion of disposal wells. Bachu et al.[4] have evaluated the effects of deep well injection of wastes in the Cold Lake area. They conclude that injection of wastewater in this area has only local effects, which are limited to the area surrounding the injection wells. This study helped to clarify and eliminate concerns regarding liquid waste migration over large distances.

Fresh Water

Fresh water requirements play a significant role in the design and operation of pilot and commercial scale, steam based, in situ oil recovery operations. The water needs of an in situ facility include; supply for generation of steam, the cooling of inlet production and, the various utility functions throughout the plant. The major use of fresh water is for the steam boiler requirements for steam production. The 'rule of thumb' target for economic production of oil by steam based methods is 4 cubic metres of steam as cold water equivalent per cubic metre of oil produced (i.e. 4/1 SOR). The SOR for operations in Alberta vary from 2/1 to 6/1 depending upon the type of reservoir under recovery and the nature of the steam recovery technology being used.

With in situ recovery methods water is co-produced with the bitumen and heavy oil. Since the freshwater supply is limited, it is desirable to recycle any water that may be recovered from the operations, rather than dispose of it completely as production waste.[5] Recycling offers significant environmental advantages in that it reduces the consumption of freshwater resources, and reduces

the volume of waste water requiring deep well disposal.

The reuse of produced waters for steam generation has been in practice since the early 1960's in California. Within Alberta, Esso Resources conducted the first recycling pilot tests at Cold Lake in 1978.[6] Other commercial in situ operations have since initiated some form of produced water treatment, however, it is still the Esso facilities at Cold Lake which currently contain the most extensive recycle operations.

Water produced during the in situ recovery process contains several impurities which must be removed, if this water is to be used as feed to a steam generator. An example of produced water composition is given in Table 3. A variety of technologies and processes have been tested and evaluated in various configurations for free oil removal, as well as; softening, silica removal, dissolved solids reduction and dissolved organics removal.

A requirement for operators to maximize recycle of produced water is embodied in Alberta's long-term management plans for in situ oil sands facilities in Alberta. This is apparent from the recently released, 'Water Recycle Guidelines', issued by the ERCB and Alberta Environment (ERCB, 1989).

Table 2 illustrates the amount of water required to recover 25% of the total bitumen in Alberta and the amount of water required to recovery one million barrels per day of oil by steam in situ recovery. The amounts of water required, without any recycle of produced water, are compared to water requirements with 75% recycle of produced water. A range of requirements is stated for the 75% recycle case since the volume of produced water may vary with the particular reservoirs under recovery. A recycle of 75% of produced water is considered to be technically feasible with current technology for the bulk of anticipated produced water. It is evident from Table 2 that the volume of water required without the use of recycle technology in this scenario is large. For example, with 75% produced water recycle, the production of one million barrels per day of oil requires a volume of water equivalent to only about 4-7 minutes of the average flow of the Athabasca River.

Gaseous Emissions

Gaseous emissions from in situ facilities have two general forms; flue gases and produced gases. Flue gas is produced from the combustion of fuel for steam generation. Produced gas is associated with bitumen or heavy oil production (gaseous emissions from the formation itself) and is essentially light hydrocarbon vapors.

Small volumes of produced gases are vented from the production well annulus, via the casing vent. In the past, annulus vent gases have, on occasion, been vented directly to the atmosphere. However, tighter restrictions and controls have resulted in the installation of facilities to allow the continuous collection and combustion of vent gases. The majority of produced gas is routed to a flare stack for combustion and conversion of any toxic hydrogen sulphide (H_2S) present into sulphur dioxide (SO_2).

Since sulphur free natural gas is currently the most common fuel used in oil field steam boilers, the sulphur emissions from in situ recovery operations in the flue gases are quite modest in comparison to other operations in Alberta as illustrated in Table 4. In the future, as in situ production grows, a switch to other fuel sources may be necessary with low sulphur Alberta coal considered as an attractive alternative. The options for fuel usage are considered later in this paper.

Solid Wastes

The majority of solid wastes created at an in situ recovery facility are the oily solids by-products of the oil produced from the production wells. During the separation of the oil, water and sand in the free water knock-out vessel, oily sand accumulates at the bottom of the vessel and must be periodically flushed to a desand tank. When the desand tank is full, the oily sand is then transferred to a lined pit or tank for further storage, treatment and disposal. Handling and disposal of this oily sand is a long standing concern for heavy oil operators. The majority of disposal techniques utilized for oily solids include the following:

- Recycle: As much of the oil as possible is recycled back into the plant for recovery as product.
- Dust Suppression: Providing the waste meets ERCB criteria (in terms of hazardous components and other chemistry) and consent is obtained from local authorities, oily fluids may be used for dust suppression on gravel roads.
- Road Surfacing: Providing that the fluid content of the solids has been adequately reduced, and the constituents of the oily solids pass the criteria mentioned above, approval may be granted for limited use in road surfacing (using appropriate road surfacing techniques).
- Reclaimers: Several technologies have been developed and are being assessed for the clean-up and reclamation of oily solids. Some of these technologies include;[8] aqueous washing or leaching, electro/chemical, solvent extraction, bioremediation, flotation and thermal recovery. The AOSTRA/Taciuk[1] process, which uses a rotating kiln to pyrolize oily wastes is now commercially available for reclaiming oil contaminated material.

FUEL SOURCES FOR IN SITU RECOVERY

Steam based methods for in situ thermal production of bitumen and heavy oil are by far the most predominant method in Alberta and Worldwide. In situ combustion based methods produce only about 4% of the thermal in situ production on a world wide basis. In Alberta the use of oxygen for in situ combustion recovery is showing promise. AOSTRA, with BP Canada, have developed oxygen based in situ combustion recovery technology at the Marguerite Lake pilot in the Cold Lake oil sands. Combustion using air, as a method to recover additional oil following waterflooding, is showing promise at the AOSTRA supported Countess B project operated by PanCanadian.

Energy Requirement for In Situ Recovery

Steam Based In Situ Recovery. The fuel required to generate steam is the largest fuel requirement for in situ recovery by steam based methods. In addition to the energy required for steam production, electrical energy is required to run the boiler water feed pumps, transfer pumps, instrumentation, lights, and other aspects of the facility. The energy requirements for a commercial scale steam based in situ recovery operation for a 'typical' Alberta oil sands application with an assumed 4/1 SOR, are provided in Table 5.

Combustion Based In Situ Recovery. With an in situ combustion recovery process, air or oxygen is injected to burn a portion of the oil in the reservoir and thus produce the heat necessary for thermal recovery. Water is injected in some cases to spread the combustion heat throughout the reservoir to aid in recovery. The largest component of required energy is for the compression of air to be injected into the reservoir. Where oxygen is used, it is usually delivered to the plant site as liquid oxygen. The on site energy requirement to inject oxygen is small, but the energy requirement to produce the oxygen off site is somewhat equivalent to air compression depending on the process used. The 'rule-of-thumb' target for economic production of oil by air based in situ combustion method is 2200 standard cubic metres of air per cubic metre of oil produced. The energy requirement for a 'typical' Alberta based in situ combustion recovery operation are presented in Table 6.

Although the in situ combustion process offers the promise of lower amounts of external energy input to operate the process, the use of in situ combustion recovery methods has not become widespread due to the difficulties of controlling the process in the reservoir.

Energy Required for In Situ Recovery in Alberta. Steam based in situ recovery methods appear most likely to be used to recovery the bulk of the bitumen and heavy oil in Alberta. Should steam based methods be used, and a recovery factor of 25% of the oil in place be achieved for all the bitumen inplace in Alberta, the total requirement for fuel to raise steam would be about 771,500 petajoules. This amount of energy requirement is compared to the total amounts of energy available in Alberta[9] in Table 7.

The amount of energy required for steam raising for in situ recovery of the total Alberta bitumen is beyond the current reserves of energy available in the province from natural gas or coal. However, the reserves of energy in Alberta are very substantial when compared to the yearly energy requirement for steam raising for in situ recovery even at a rate of 1,000,000 barrels per day of bitumen production by in situ steam methods. A million barrels per day of production is chosen as a comparison case because this production amount is comparable to the current total oil production in Alberta.

Fuel Source Options for In Situ Recovery

Natural Gas. Natural gas has been the fuel of choice for steam raising at in situ recovery projects. Natural gas is clean, easily transported, readily available and currently relatively inexpensive. However, the price of natural gas is anticipated to rise with increased demand, especially due to the increase in requirements for clean fuel for environmental reasons. The price predictions on natural gas and oil from the National Energy Board of Canada[10] indicate that natural gas prices may rise more rapidly than oil prices. Projection of the forecast indicates that oil and gas prices may become equivalent about the year 2015.

The use of natural gas, which has a high hydrogen/carbon ratio to produce a fuel (i.e. bitumen) with a low hydrogen/carbon ratio would seem to be contrary to the objective of producing fuels with a higher hydrogen/carbon ratio (in order to lower the carbon dioxide release of the fuel upon usage). As indicated in Table 7, natural gas production would have to increase by about 22% to provide the energy for steam boilers to recover 1,000,000 barrels per day of bitumen by in situ steam recovery.

Coal. Alberta has massive coal reserves, enough to keep the provinces existing coal-fired electrical power plants supplied for about 1100 years.[9] Alberta coals are low in sulphur typically with 0.2 to 0.7 percent sulphur and thus are suitable for burning with relatively low sulphur dioxide emissions. If coal were used for steam production for in situ recovery at 4/1 SOR, a tonne of coal would provide enough energy to produce 2.4 cubic metres of bitumen. Use of coal would release about 27% more carbon dioxide than natural gas when used as a fuel for

steam generation.[11]

The use of coal as a fuel to produce bitumen is in keeping with the objective of producing fuels with higher hydrogen to carbon ratio, since bitumen has a higher natural hydrogen to carbon ratio than coal. A test of the use of coal in a conventional 50 million BTU/hour oil field steam boiler is currently in the construction stage.[12] Esso Resources Canada Ltd., TransAlta Utilities, Shell Canada, and Alberta Power, with financial support from the Alberta Office of Coal Research and Western Economic Diversification Canada, are undertaking an $11 million demonstration project to test a Low No_x/SO_x (LNS) burner on a coal fired steam generator at Esso's Cold Lake Oil Sands project. The steam generator is scheduled to startup in 1990. Results of the project will be available in 1991. As indicated by Table 7, if coal were used as fuel for steam boilers to recover 1,000,000 barrels per day of bitumen by in situ steam recovery, the coal production in Alberta would have to increase by about 110%.

Bitumen or Heavy Oil. Bitumen and heavy oil have been demonstrated to be feasible as fuels for use in conventional oil field steam generators. The use of produced bitumen or heavy oil as a fuel for steam raising would eliminate or greatly reduce the requirement for outside fuel such as natural gas or coal. Bitumen and heavy oil are not currently favored as fuels for steam raising because it is currently economically attractive to sell the bitumen or heavy oil and use a relatively less expensive fuel (i.e. natural gas). If bitumen were used as the source of fuel for steam raising at a steam based in situ recovery project, about 30% of the produced bitumen would be required for fuel. For 1,000,000 barrels per day production of bitumen in situ steam recovery, as indicated in Table 7, the amount of bitumen required for steam fuel would be about equal to the entire current bitumen and synthetic crude oil production.

Bitumen and heavy oil are not attractive fuels from an environmental stand point because the sulphur content is from 4 to 6% by weight. Thus stack gas cleaning methods would be required to control sulphur dioxide emissions if bitumen was to be widely used as a fuel. Bitumen and heavy oil would release about 20% more carbon dioxide than natural gas for the equivalent energy provided for steam generation.[11]

Nuclear Energy. Nuclear energy has been considered as a source to provide steam for in situ oil recovery. However, nuclear energy stations require a relatively large scale to be economic and are not transportable. With in situ recovery, several smaller steam production facilities are required over the life of a project as areas of the reservoir are depleted and facilities are moved to reduce steam heat losses in surface lines. The steam pressures required at certain stages of an in situ recovery operation are also not readily available from nuclear reactors, as currently configured.

There would be virtually no carbon dioxide or sulphur dioxide emissions with a nuclear reactor, but radioactive waste disposal and safety of operation concerns are major issues with the public.

PERSONNEL FOR IN SITU RECOVERY

In situ recovery operations are more labor and personnel intensive than conventional oil recovery production. For a commercial scale, steam based, in situ recovery operation in Alberta, it is anticipated that about 50-100 area operations[13,14,15] personnel will be required for each 1000 cubic metres per day production. For production of one million barrels/day of oil by in situ recovery, approximately 8,000-16,000 operations personnel will be required as direct employment to operate the facilities. In addition to the direct employment of personnel at site, there will be additional off site personnel associated with the projects as well as the 'secondary' employment created.

The major oil sands and heavy oil reservoirs are located in areas with small population base. The growth in population due to the increase in in situ recovery may have some impact on the environment resulting from the increased numbers of people in the areas.

CONCLUSIONS

The production of oil sands bitumen and heavy oil by in situ recovery methods will increase in Alberta and Canada in the future to meet the shortfall in petroleum production from declining conventional light oil production. Many of the environmental aspects of in situ recovery of oil sands and heavy oil are similar, if not identical to conventional oil production. For example, the handling of mud pits and surface disturbance are identical or very similar for a well drilled for conventional oil or a well drilled for in situ recovery. The in situ recovery methods will require more closely spaced wells, but the use of cluster/deviated drilling methods, horizontal wells and potentially underground shaft and tunnel methods, greatly reduce the impact on surface disturbance. Water will be required for future in situ recovery methods, but the development and implementation of efficient recycle methods will reduce the water requirement to very manageable levels. Oily solid wastes will be produced by in situ methods, however, as these amounts increase, the technical methods to safely handle these wastes will evolve from work that is already advancing.

A difficult aspect of in situ recovery of oil sand and heavy oil is the fuel source to generate the heat

necessary for the thermal in situ recovery methods anticipated. Low sulphur fuels or efficient stack gas cleanup methods are anticipated to be available. However, a non-carbon dioxide producing fuel supply does not appear to be readily at hand. The contribution of in situ recovery methods to the carbon dioxide production world wide will be small, but significant. Research efforts now underway are aimed at the critical problem of reducing the fuel requirements for in situ recovery methods. A reduced fuel requirement is not only desirable from an environmental aspect, but is also desirable to improve the economics of in situ production. Thus, reduced fuel usage for in situ recovery is a high priority matter.

In situ production methods require more personnel per cubic metre of production than conventional oil production. Population centres near in situ recovery operations will have growth based on the jobs which become available as in situ production increases. As with any growth in a population centre, the maintenance of a high quality environmental situation will be a matter of civic priority and pride.

The future anticipated growth of in situ recovery from oil sands and heavy oil is anticipated to have a relatively minor environmental impact due to existing, as well as developing, technology related to the recovery methods.

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Table 1

Surface Disturbance by In Situ Recovery Methods

Reservoir Access Method	Surface Area Disturbed* (% of Area)
Vertical Wells	40-60
Cluster Drilling	10-20
Shaft and Tunnel with Horizontal Wells	3-5

* For comparable commercial scale operations including well pads, roads, plant site and pipelines.

Table 2

Steam Boiler Water Requirement for In Situ Recovery in Alberta

Boiler Water Required	Estimated Fresh Water Requirement	
	100% Fresh Water	75% Produced Water Recycle
	*Million Cubic Metres/ Athabasca River Flow**	*Million Cubic Metres/ Athabasca River Flow**
Water Required for Steam Raising to Recover 25% of Total Alberta Bitumen by In Situ Recovery (4/1 SOR)	270,000/ 13.5 years	67,500-120,000/ 3.4-6.0 years
Water Required Per Day for Steam Raising to Produce 1 Million Barrels Bitumen Per Day by In Situ Recovery (4/1 SOR)	0.63/16 minutes	0.16-0.28/4-7 minutes

* Comparative water flow to Athabasca River which flows at about 20,000 million cubic metres per year (17 million acre feet per year below Fort McMurray).

Table 3

Feedwater Specifications for Once-Through Steam Generation Boilers

Parameter	MAC[a] (mg/L)	Produced Water[b] (mg/L)
TDS	8000	20,895
TSS	0	17
Total Hardness ($CaCo_3$)	0.5	1,890
Silicas (SiO_2)	50	150
Oil	1	76
Dissolved Oxygen	0.04	0.5
Iron	0.05	1.0

[a] MAC - Maximum Acceptable Concentration (after CH2M Hill, 1986)[6]
[b] A sample analysis of effluent from an IGF unit.

Table 4

Average SO_2 Emissions From Specific Industrial Sources in Alberta for the Period 1981-1985 (After Alberta Environment, 1988)[7]

Industrial Source	SO_2 Emission (Tonnes/day)
Gas Plants	342
Power Plants	192
Pulp & Paper Mills	7
Fertilizer Plants	11
Refineries	20
Sour Oil Production	76
Oil Sands Mining Plants	388
In Situ Heavy Oil Operations	10
Other Industry Sources	8

Table 5

Energy Requirement for Commercial Scale
Steam Based In Situ Recovery
(Basis 4/1 SOR)

Energy Type	Energy Gigajoule/Cubic Metre Oil
Steam Boiler Fuel	12.7
Electrical Energy	0.2

Table 6

Energy Requirement for Commercial Scale Air *Based In* Situ Combustion Recovery (Basis 2200 Standard Cubic Metres of Air/ Cubic Metre of Oil)

Energy Type	Energy Gigajoule/Cubic Metre Oil
Air Compression (Fuel or Electrical)	7.3
Electrical Energy	0.2

Table 7

Total Energy Required for In Situ Production in Alberta

Requirement/Source	Total Energy Amount (petajoules)	Yearly Energy Amount (petajoules)
STEAM RAISING		
Energy Required for Steam Raising to Recovery 25% of Total Alberta Bitumen by In Situ Recovery (4/1 SOR)	771,500	–
Energy Requirement per year for Steam Raising to produce 1,000,000 barrels bitumen per day by In Situ Steam Recovery (4/1 SOR)	–	700
ENERGY SOURCES		
Remaining Reserves in Alberta at End of 1988;		
Natural Gas and Equivalent	63,000	–
Coal	573,000	–
Marketable Production 1988 in Alberta;		
Natural Gas and Equivalent	–	3,200
Coal	–	640
Conventional Oil and Equivalent	–	2,450
Bitumen and Synthetic Crude Oil	–	735

Figure I
Worldwide Distribution of Oil Sands Deposits

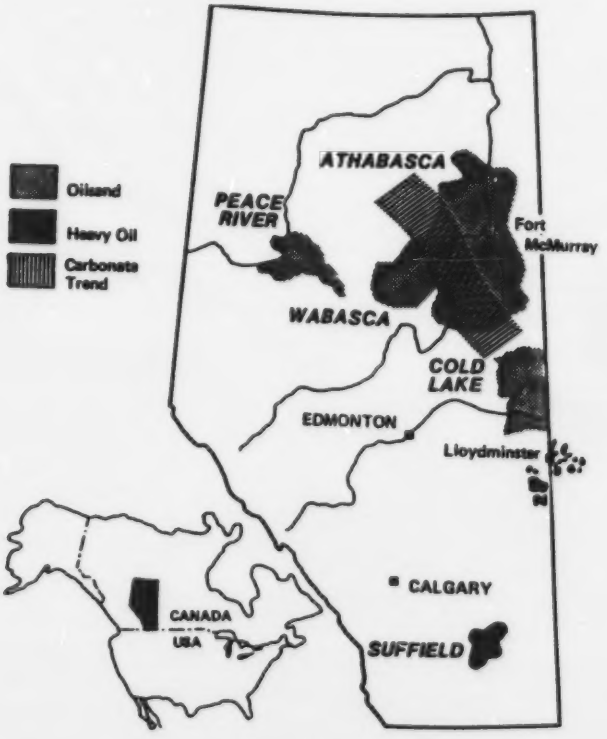

Figure II
Major Alberta Oil Sands Deposits Plus Grosmont Carbonate

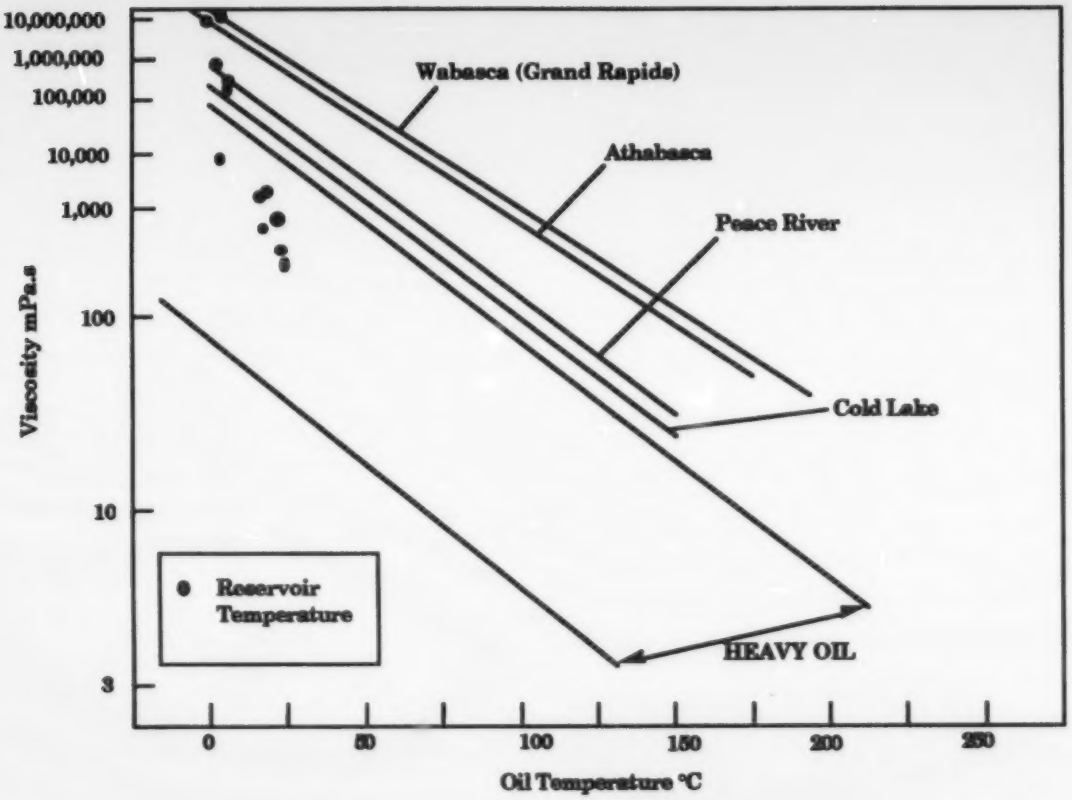

Figure III
Viscosity - Temperature Relationship of Bitumen and Heavy Oil

The Shell/AOSTRA Produced Water Treatment Pilot Plant; Testing The Limits

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Background. Shell Canada's Peace River facility was expanded in 1986 from the original design pilot-scale bitumen production of 550 m^3/d to 1600 m^3/d. Future expansion of the Peace River Complex requires a technically and economically sound method of reuse of produced water. Unique features at Peace River, such as the high alkalinity in the produced water and separation of the 80 percent steam into dry vapour and blowdown, make reuse a significantly different challenge than in other locations.

Statements had been made to the effect that high silica concentrations in steam generator feedwater could be tolerated as long as divalent cations were absent and the alkalinity was sufficiently high. In order to verify the technical feasibility of a produced water treatment scheme using ion exchange softening without silica removal, Shell constructed and operated a pilot facility at the Peace River site during 1987-1988. The Alberta Oil Sands Technology and Research Authority (AOSTRA) participated in this project.

OPERATING DATA/EXPERIENCE REQUIREMENT

The main constraint to produced water reuse is the presence of contaminants that affect the ability to operate the softeners and steam generators. These contaminants are oil, silica, hardness, alkalinity and total dissolved solids. The concentration of each varies throughout the Peace River reservoir production sequence.

Determination of acceptable technical limits was the objective of the Shell/AOSTRA produced water treatment pilot plant project. Current industry technical limits include the total dissolved solids to the ion exchange softeners to control hardness leakage, silica concentration to the steam generators to control silica scaling, and total suspended solids and alkalinity to the steam generators to control metal erosion/corrosion. Of these limits, silica is the least understood and the most expensive to meet.

There are numerous silicate minerals in existence, all with solubility that varies with pH and the concentration of the various cations. Any time that silica is present, there exists the risk of scaling in the steam generator. The acceptable technical limit for silica concentration in the feedwater as stated in previous publications by industry and manufacturers has ranged from below 50 mg/L up to 170 mg/L. These levels have been experienced at various oilfield steam generation facilities in North America under widely varying operating conditions and water qualities.

Silica removal from produced water is typically accomplished using lime softening. Previous process study work had indicated that unusually large quantities of lime sludge would be produced because of the high alkalinity normally in Peace River produced water. There were also claims being made that high alkalinity would serve to increase the concentration of dissolved silica that could be tolerated in the steam generator feedwater.

The prospect of being able to avoid the cost and solid waste production associated with lime softening was attractive. However, Shell determined that the risk associated with using ion exchange only for water softening, mainly potential scaling of the steam generator tubes, required demonstrated operation at the pilot level prior to full-scale commercialization. With participation from AOSTRA, Shell constructed a pilot plant to evaluate ion exchange softening and 100 percent steam generation on typical produced waters obtained during operation of the Peace River Expansion Project (PREP) and to determine the practical maximum allowable silica concentration.

OBJECTIVES

The primary objective of the pilot test was to determine the feasibility of operating a once-through steam generator on 100-percent recycle of produced water at the TDS and silica concentrations experienced

under field conditions, or if 100-percent produced water recycle was not practical, determine the upper limit of produced water recycle. Secondary objectives were defined to answer less critical questions about produced water reuse and were contingent on available time and budget. They included:

- Obtain operating experience under field conditions on produced water recycle up to 100 percent using the oil removal and softening processes selected for the pilot.
- Monitor the effects of oil and particulate fouling on the process under field conditions.
- Demonstrate the effectiveness of a skim/surge tank and cartridge filter in protecting the ion exchange softeners from oil and particulate fouling.
- Demonstrate the effectiveness of surfactant wash and gas scour techniques in restoring ion exchange effectiveness following oil fouling.
- Confirm design criteria for the strong acid cation (SAC) and the weak acid cation (WAC) ion exchange unit processes.
- Demonstrate the effectiveness of the softening process in treating the produced water to essentially zero hardness.
- Confirm the operating costs under actual field conditions, particularly regenerants.
- Test lining materials for use in commercial-scale WAC units.
- Evaluate corrosion in steam lines and liquid phase lines downstream of the steam separator.
- Evaluate caustic embrittlement of liquid phase lines from the steam separator.
- Evaluate the effect of heat flux in the steam generator on scaling.

TEST PLAN

A key document in the preparation for the pilot test was the test plan. This document evolved through extensive consultation with Shell's engineering, operations and research staff. It was developed in parallel with the pilot facility design to ensure that the two were completely compatible. A process schematic of the pilot plant is shown in Figure 1.

The test plan was developed to focus on the primary objective while operating the support equipment and capturing available data to achieve the secondary objectives. The primary feature of the test plan was the operation of the steam generator at a fixed set of conditions for a period of one month, a shutdown and internal inspection and then another month of operation at new conditions. The conditions for the following month were determined after review of the inspection results. A decision tree illustrating this process is shown in Figure 2.

The ion exchange performance data were obtained by operating for periods of time at different regeneration and flow conditions. A sufficient number of runs at each condition were carried out to enable minor run-to-run variations to be averaged out. Selected conditions were repeated periodically through the program to check for long-term changes in resin performance.

Data relating to other performance parameters were obtained whenever the plant was operating. Data on resin and steam generator tube cleaning procedures were obtained as these procedures were required.

PILOT FACILITIES

The pilot facilities consisted of a 1610-kW (5.5-MMBtu/hr) high pressure steam generator, oil removal and softening equipment for the feedwater, chemical systems for ion exchange regeneration and modification of the water chemistry, tankage, utilities and a computer-based control and data acquisition system. Process connections to the main plant consisted of produced water from two points, fresh water, gas, instrument air, heating glycol, and the relief header. The only connection to the main control room was an H_2S alarm.

The design throughput of the pilot plant was selected to balance ease of inspection with cost and availability of process equipment.

It was determined that the steam generator tubes should be at least 1" nominal pipe in order to be able to properly inspect them internally. Schedule 160 pipe was chosen to provide an extra margin of safety because of the possibility that the tubes would be stressed beyond their normal duty. The pilot steam generator was specifically designed as a test unit that would be as close as possible to full-scale steam generators and provide useful information for design and operation of commercial units. Computer modeling of the heat transfer and fluid parameters was carried out to help the comparison of pilot and full-size units. Parameters that were maintained at values equal to full-scale steam generators were:

- Waterside pressure and temperature
- Waterside velocity and flow regime
- Average heat flux in each heat transfer section
- Steam quality profile though the waterside path
- Fireside temperature

Complete geometrical and thermodynamic similarity between two steam generators differing widely in size is impossible. Some of the factors that were not the same in the pilot as in a full-scale unit are:

- Radiant section L/D ratio
- Relative roughness of tubes
- Tube spacing
- Volumetric heat release

The steam generator, built by Struthers T-I-W in Calgary, was heavily instrumented with flow meters on all streams, thermocouples at all available process points and skin thermocouples on many of the tubes. It was also equipped with a high pressure separator and a two-stage blowdown flash system on the skid.

The feedwater treatment system consisted of a skim tank and cartridge filter for final oil removal from the produced water, blending at a controlled rate with fresh water to enable control of the silica concentration, chemical dosing to enable control of the TDS and alkalinity independently from the silica concentration, and a three-stage ion exchange softening train.

The source of produced water for most of the pilot program was downstream of the oil removal system in the main plant. The skim tank and cartridge filter in the pilot were mainly for protection from upsets in the main plant. Only small amounts of oil were removed in these two steps.

Blending with raw water was the normal mode of operation. To maintain the TDS and alkalinity at constant levels regardless of the percent of produced water in the blend, sodium chloride and sodium bicarbonate were added to bring the blended water composition up to a predetermined design level. For part of the program when the produced water usage was relatively high, it happened that the TDS and alkalinity were also higher than normal so that these two values actually exceeded the "design" values.

The ion exchange system consisted of three stages, a primary strong acid resin exchanger, a secondary strong acid resin exchanger and a weak acid resin polisher. The first two were macroporous resins regenerated with a 10 percent brine solution and the polisher was a macroporous resin regenerated with hydrochloric acid and caustic soda. Each vessel was 610 mm in diameter and contained approximately 1.2 m of resin. The polisher vessel was fitted with a sample point within the resin bed approximately 200 mm above the bottom collector. Samples were taken at that point to detect hardness breakthrough. Even when hardness was detected at the upper sample point, it would not have appeared in the product water.

Additional tankage included a storage tank for steam generator feedwater and a disposal tank that was used to store excess produced water, ion exchange regeneration wastes and miscellaneous wastewater for transfer to the main disposal system.

The control system consisted of a PLC that interfaced with the process and provided all logic and analogue controls. A microcomputer-based control system provided operator interface graphics and data acquisition and manipulation. Data were gathered from the primary elements through the PLC and were entered manually from the keyboard. Reports were generated on a daily basis and as a monthly summary for steam generator operation and basic water characterization. Reports for the ion exchangers were generated for each run and were summarized for each series of runs at similar conditions. The operating system not only collected and reported the data, but also carried out extensive calculations to report heat transfer coefficients, energy balances, ion exchange resin capacity and so on. This feature considerably reduced the manual effort in preparing data for analysis. The reports prepared by the operating system were downloaded in a format compatible with common spreadsheet programs for use at other locations. Raw data files for each day's operation were archived to provide for possible review later.

The pilot plant was built in several sections. The steam generator, steam separator and blowdown flash system were contained on single skid and housed in a field-erected building. The tanks were shop fabricated, lined and insulated, and located in an earthen containment dike. The remaining facilities were shop fabricated in two building skids set adjacent to each other. One module is a chemical storage and feed room. The other contains the water treatment process area, the control room and the electrical room. The plant was installed in an area adjacent to the Peace River Complex central plant but could be relocated relatively easily if required.

RESULTS OBTAINED

Specific results are contained in the Project Report, which is available through AOSTRA's technology transfer program and will not be discussed in detail here. Results, conclusions and recommendations were presented relative to all project objectives as well as some relevant points that were not specifically researched.

Results relating to operation at high silica concentrations include:

- Assessment of scale detection methods
- Effect of high silica feedwater on silicate distribution, silicate species, and scale deposition
- Fluid conditions throughout the steam generator
- Silica solubility
- Steam quality measurement
- Scale removal considerations
- Equipment sizing considerations

The operating experience gained was documented in results and conclusions with respect to suitability of particular materials, control of high pressure saturated water, scale removal procedures, compatibility of various waste streams, steam quality measurement and distribution of H_2S downstream of the steam generator.

The effect of oil and particulate carryover on the ion exchange resin and the steam generator is presented.

Limited results on the effectiveness of the skim tank and cartridge filter were obtained due to the normally clean condition of the produced water.

Both bench- and field-scale trials of resin cleanup methods were carried out. The effects of the methods tested are presented and discussed.

The SAC resin exchangers were operated under a systematic variation of regenerant and hydraulic loadings. In addition, there was considerable variation in feed TDS due to operating on 100 percent fresh water, the design blended TDS and at higher than planned TDS. Resin capacity and steady-state leakage were compared to the manufacturer's published data. Breakthrough curves showing the depth of the active exchange zone were plotted for a number of runs. Also the effectiveness of regeneration with different amounts of brine was investigated. Similar results using a gel SAC resin were obtained for a short period near the end of the program.

No changes in the regeneration level were made to the WAC operation. Performance parameters were compared to the manufacturer's data. Off-normal operations that resulted in hardness leakage were documented.

A process optimization study based on the operating data from the pilot program and on the plant capacity planned for the next expansion at the Peace River Complex was carried out.

Various materials were used in the construction of the weak acid ion exchanger, and test coupons with other lining materials were mounted inside the vessel. Inspection results for all materials are presented in the report.

Several methods of corrosion monitoring were used during the pilot test. Visual inspection, strip-type coupons, electric corrosometer probes and ultrasonic thickness measurement were used at a number of locations. The effectiveness of each method for different types of corrosion and for different locations is discussed as well as the results of the measurements. The corrosion results are discussed in terms of process conditions such as temperature and fluid velocity, carbonate dissociation, sulphide attack and suspended solids.

An ASTM caustic embrittlement device was installed in each of two pressurized blowdown lines. The suitability of such a device in produced water service is discussed.

The feedwater preheater was heated with high pressure steam rather than with hot water from the outlet of the convection section as is normal. This was done if order to allow operation at low heat flux while maintaining total mass throughput.

The pilot project was successful in answering most of the questions posed at the start. The operating experience gained provided greater insight into the challenges to be expected and of the questions that remain to be answered. The results obtained in this work are specific to Peace River produced water; in fact, considerable effort was expended to ensure that most water characteristics were held constant. The effect of alkalinity concentration, trace cations and interaction with other components still needs to be investigated and is an opportunity for cooperative industry research.

ACKNOWLEDGMENTS

The support of the project sponsors, Shell Canada Limited, Pecten Canada Limited, and the Alberta Oil Sands Technology and Research Authority, is gratefully acknowledged.

Numerous individuals within Shell Canada, both in Calgary and in Peace River, provided critical technical and operational input to the study.

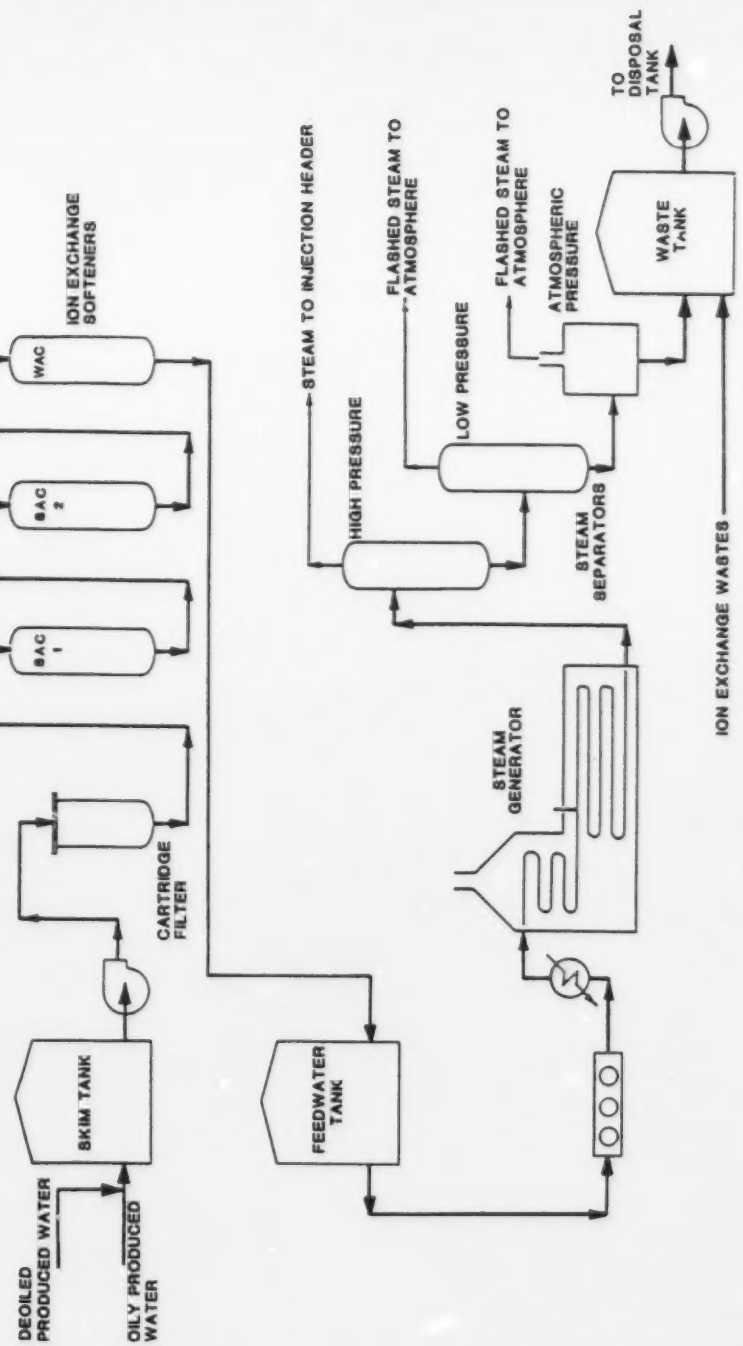

Figure 1
SHELL/AOSTRA PILOT PLANT
PROCESS SCHEMATIC

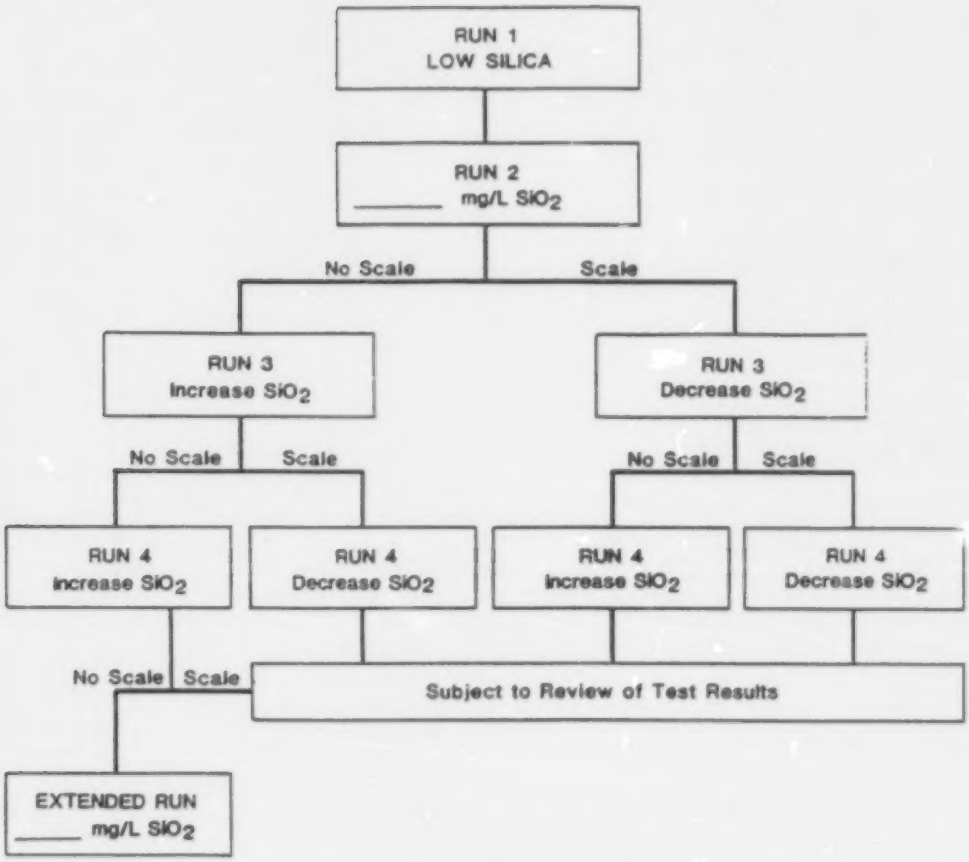

Figure 2
SILICA CONCENTRATION DECISION TREE

The AOSTRA Taciuk Process
The Flexible Alternative For Oily Waste Treatment

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Abstract. The AOSTRA Taciuk Process (ATP) was developed initially for direct thermal processing of oil sands and oil shales to produce a partially upgraded synthetic crude oil. Recent extensive test work with a 5 tph pilot plant has proven its waste remediation capabilities with a wide range of oily waste feedstocks. The ATP has been successfully tested on heavy oil production wastes, PCB contaminated soils, hydrocarbon emulsions, and bituminous sand/shale mixtures. Research is continuing with other feedstocks such as selected municipal wastes, acidic refinery wastes, and coal tar residues.

The ATP produces a concentrated hydrocarbon product, separate water products and a combusted solids residue. Hydrocarbon products are potentially suitable for recycle as plant feed or saleable product. Contaminated oils are collected for economical disposal. Water products are collected and may be treated separately. The solids discharge is environmentally acceptable and does not require further processing to pass EPA leachate tests.

The ATP was developed jointly by the Alberta Oil Sands Technology and Research Authority (AOSTRA) and UMATAC Industrial Processes, A Division of UMA Engineering Ltd. The most recent work with oily waste materials led to the recent commercial application of a 10 tph transportable ATP for PCB contaminated waste treatment.

The performance of the pilot plant tests and the analyses of feed and products are described. Treatment costs are presented for a range of treatment capacities.

INTRODUCTION

Industry is being asked to become more accountable for wastes produced in the course of conducting business. A large portion of this waste is hydrocarbon or oil contamination of host solids.

Waste materials are a liability in any industry and as legislation forces action, the oil industry must seek out the most economical oily waste remediation options available.

The AOSTRA Taciuk Process (ATP) utilizes thermal separation technology to separate and process certain components from host material, offering significant cost savings over thermal destruction methods such as incineration. The ATP effluent or oil product may be re-used, separately treated or disposed of in an efficient and economical manner. The treated solids residue portion of the material is environmentally safe and may be disposed of without further treatment.

The ATP technology was developed jointly by the Alberta Oil Sands Technology and Research Authority (AOSTRA) and UMATAC Industrial Processes (UMATAC) over a 14 year period. A major research and process development facility was constructed in 1977 in Calgary, Alberta. This facility is comprised of a small scale, batch testing apparatus, and a continuous 4.5 tonne/hour pilot plant unit. The facility is supported with a laboratory and personnel services. The pilot unit is capable of continuous operation with staffing available to maintain around-the-clock, 24 hour/day operation.

AOSTRA has committed more than $18 million to the development of the ATP. The process was originally conceived and developed for the extraction and primary upgrading of bitumen from mined Athabasca oil sands. It has been tested extensively for the processing of oil shales and most recently it has been demonstrated as an effective method for treating soils and sludges which are contaminated with oil and other organic wastes.

It has been this recent work with oily wastes that has resulted in the construction of the first commercial ATP waste treatment plant in 1989.

A 10 tonne/hour transportable plant has been constructed for remediation of a PCB contaminated site in the United States. As of February, 1990 it is temporarily situated at the AOSTRA research facility, performing feedstock evaluations while awaiting site preparation completion at its intended site in the United States.

The ATP has distinct advantages over other popular large scale remediation technologies such as incineration and solvent extraction. The heart of the ATP is a rotating Processor, offering unique processing capabilities ideal for oily waste treatment including:

- the separation and concentration of the hydrocarbon constituents making it possible to individually re-use, treat or dispose of them as required to meet environmental requirements.
- environmentally acceptable discharged solids, passing leaching criteria.
- an efficient internal heat recovery system, preheating the incoming feed by cooling the exiting combusted solids residue and flue gases resulting in reduced fuel consumption.
- an anaerobic atmosphere for treating the waste material as it is processed at the higher temperatures required for pyrolysis.
- simple and safe operation; with process vessels operating at near atmospheric pressures, a single vessel producing the process vapours, capable of almost instantaneous quenching of process reactions in an emergency.

Incineration requires raising the entire feed to temperatures in excess of 1100°C. The ATP heats the liquid portion of the feed to temperatures up to 600°C and the solids to temperatures of up to 750°C. This results in significant energy savings over incineration.

In addition, incineration requires large amounts of additional combustion air to completely burn hydrocarbons in the feed. This results in tremendous flue gas rates at high temperatures.

PROCESS DESCRIPTION

The ATP is a thermal extraction process for separating hydrocarbons from granular host solid materials. The process occurs in a rotary vessel, or Processor, which preheats, vaporizes, pyrolyzes, removes hydrocarbon vapours, burns coke byproducts and recovers heat from exiting treated solids. Products from the process are: hydrocarbon vapours, steam, gases of combustion, and inert residual tailings solids.

Two major sub-systems provide hydrocarbon vapour condensation and flue gas treatment. Refer to Figures 1 and 2 to trace the process streams, described as follows.

The contaminated feed material enters the Preheating Zone where water is evaporated from the feed, providing a steam blanketing atmosphere to reduce oxygen levels. Feed entrained air, light vapourized oil and steam are extracted from the zone and are condensed external to the Processor. The oil and water are separated then sent for storage, disposal or treatment as required. Noncondensable gases from the Preheat, reduced to mostly containing air, are directly injected into the Combustion Zone.

The preheated material is transported to the Reaction Zone where it is mixed with hot recycle solids to further heat the incoming feed stream to higher temperatures. In the Reaction Zone, lower boiling hydrocarbons are vapourized and any higher boiling hydrocarbons may be pyrolyzed. This process produces two streams; a vapour stream comprising gas and liquid fractions and a coke residue which is deposited on the solids. The coked solids are routed to the Combustion Zone, and the vapour stream is extracted from the Reaction Zone.

The vapour stream is drawn through a cyclone to remove entrained solids, then to a vapour scrubber to perform the first stage of vapour cooling and capture of fine dusts. The fine dusts are collected in the condensed, heaviest hydrocarbon fraction or bottom oil. This bottom oil may be consumed as a fuel for the Processor, or recycled for re-pyrolysis to extinction, thus eliminating the dust loading and the heaviest oil fractions of the oil product. In the case of hazardous component processing, the bottom oil is directed for disposal as a hazardous liquid.

The cleaned, cooled vapours are directed to the fractionator for the separation of the hydrocarbons into two fractions; heavy and light oils. The light oils and vapour off the top of the fractionator are drawn through a heat exchanger for condensation and separation.

The heavy oils collected in the fractionator sump and the light oils from the fractionator overhead accumulator may then be directed to product storage. The overhead water, which is generally sour, may be optionally stripped, then sent offsite for further treatment. The noncondensable gases may be burned in the Combustion Zone directly, or through an auxiliary burner, contributing as a fuel or may be flared, as required.

The coked solids residue deposited on the solids during pyrolysis is burned in the Combustion Zone to fuel the process. Auxiliary burners, firing industrial fuels, are provided to supplement the heat generated by the combustion of coke. A slip stream of the hot solids is recycled to the Reaction Zone, the remainder passing to the Cooling Zone.

The Cooling and Preheating Zones act as a countercurrent heat exchanger; hot spent solids giving up heat to the incoming feed. The heat exchange is indirect, providing isolation of the hot inert residual solids from the incoming contaminated feed.

The cooled, residual, discharged solids or tailings are dampened with water to provide further cooling and dust control, and are stockpiled. The steam produced is vented directly to atmosphere.

The flue gases from combustion are passed through a cyclone, filtered through a baghouse, scrubbed of acid components, and are discharged from an exhaust stack. The baghouse and cyclone solids are discharged with the Processor solids to a stockpile.

PROCESS CONDITIONS

The ATP as described above has four distinct zones of operation; the Preheat, Reaction, Combustion and Cooling Zones.

The Preheating Zone is designed to raise the temperature of the feed from ambient conditions to some elevated temperature appropriate to the feed type. Light hydrocarbon oil processing would require lower vaporization temperatures than heavier. Evolved vapours and steam are extracted from the zone, depleting the zone's atmosphere of oxygen. Preheat Zone exit temperatures are 200 to 300°C.

The Reaction Zone must complete the extraction of remaining hydrocarbons from the solids charge. This process takes place in an anaerobic atmosphere. The feed characterization determines the extent to which this zone must perform; whether vaporization is sufficient for extraction or if pyrolysis is required. General oily waste operation requires temperatures in the range of 400 to 600°C.

The Combustion Zone provides heat for the process. Combustion Zone temperatures of 600 to 750°C provide heat as necessary to fuel the Preheat and Reaction Zone functions. Auxiliary fuel burners are available for startup and to supplement the heat requirements during low hydrocarbon-containing feed operations. Higher molecular weight oils in the feed will produce coke when pyrolyzed. The coke is burned as fuel in this zone, reducing the auxiliary heat requirements.

The Cooling Zone accepts hot residual solids discharged from the Combustion Zone and transfers this heat to the Preheat Zone. The degree of cooling is directly related to the heating objectives of the Preheat Zone described above. Typically the cooled solids are discharged at 250 to 350°C.

If the required heat loading is very high, as in the case of a high liquid feed, additional recycle solids may be circulated directly into the Preheat Zone. This increases the circulation solids load, providing the additional thermal mass to boost the temperature in the Preheat Zone.

All four zones are automatically maintained at sub-atmospheric pressures. The Combustion and Cooling Zones are automatically maintained at a pressure of –1 mm water column (WC) gauge by means of an induced draft fan at the flue gas handling area. The Preheat Zone pressure, of about –1 mm WC, is maintained by means of a compressor downstream of the vapour condensation system. Lastly, the Reaction Zone is maintained at a pressure slightly less than any of the other three zones in order to prevent release of the products of pyrolysis or vaporization. A compressor downstream of the vapour condensation and handling systems provides the draft for the Reaction Zone vapours. Typical pressures would be in the range of –1 to –2 mm WC.

APPLICABILITY TO VARIOUS FEEDS

The ATP is capable of processing a wide variety of feed types. Originally intended to process oil sands with upwards of 17% of oil and water, the Processor operation can be adjusted to handle such widely varying feed materials as slurries, approaching 100% liquid, and dry, organic contaminated soils. Since commencing testing in 1978, the pilot plant has processed over 14,000 tonnes of oil sands and oil shales. From the first operations on wastes in 1986, testing has consumed a further 500 tonnes of oily soils and slurry wastes from the oil production, enhanced oil recovery and oil refinery industries. Hazardous waste processing has included nearly 30 tonnes of PCB containing, oily soils.

Although basically a solids handling machine, slurries and high liquid content feeds may be injected directly into the Processor, while simultaneously processing a continuously recycled charge of carrier solids. Alternately, the liquid feed could be pre-mixed with a recyclable carrier solids stream prior to entering the process.

Oversize handling capability varies somewhat with Processor size, but is limited at the upper end to 150 mm.

ATP processing viability may be determined with a small scale batch testing apparatus. This has been used successfully to screen potential feed for the 4.5 tonnes/hour pilot plant unit. The hydrocarbon yield, and organic component distribution is well represented by batch scale testing. In some instances, a continuous progression of batch, pilot and the commercial 10 tph operation have been completed.

Table 1 lists some of the feed materials evaluated for the ATP and the stage of evaluation.

1) Oily Waste. The Processor may be operated in a variety of operational modes, depending upon the characterization of the feed.

Heavy oil contaminated material may be easily treated by pyrolysis. The cracked oil would be a saleable oil product, the coked residue would be fuel for the process.

Light oil contaminated solids could be treated with the two stages of hydrocarbon recovery available in the Processor. The Preheat system could

extract a majority of the lighter components which may easily volatilize at the moderate preheating temperatures. All this lighter oil would be available as a product oil. Higher molecular weight hydrocarbons would remain with the solid phase until vaporization or pyrolysis could occur in the Reaction Zone. Pyrolysis products would be split between condensable oil and a coked residue available for combustion.

The Preheat and Reaction Zones may be controlled such that optimal product splits is achieved; reducing the extent of pyrolysis or cracking, and thus reducing the coke make and improving liquid hydrocarbon recovery.

The solids effluent appears in three main streams: roughly 90% via the Cooling Zone residual solids discharge, 9% via the flue gas cyclone underflow, and 1% via the baghouse filter dust. These streams are normally combined for treated solids product discharge.

2) Hazardous Waste. In the special case of hazardous waste, Processor operation is unchanged, however, upstream and downstream ancillaries are handled differently.

The Processor is still operated at slightly sub-atmospheric pressures, which is particularly significant with hazardous waste, as the chance for vapour release is minimal. Feed may be handled differently, in that liquid waste would be directly injected, to reduce handling equipment involvement.

The fractionation system is operated in such a manner as to provide maximum condensation of vapours into oil and water products. The concentrated oil products, containing the hazardous components would not be recycled to the Processor, but are retained for disposal at an appropriate treatment facility.

In particular, the ATP has proven capabilities for extracting PCB from soil.

Upon processing, the feed PCBs accumulate predominately within the heaviest fractions of the product oil. The remaining PCBs appear in the lighter oils and process water.

SPECIFIC WASTE FEED AND EFFLUENT QUALITY

Significant effort has been invested to examine remediation of refinery cleanup wastes, enhanced oil recovery (EOR) wastes (desand pit sludges, field tank sand), invert drill mud cuttings and PCB contaminated soils. Product recovery and quality information is available for these feedstocks.

1) Enhanced Oil Recovery (EOR). In 1987 an agreement was signed, sharing financial contribution to a program to determine the potential of the ATP to treat EOR wastes. Costs were shared between AOSTRA , Supply and Services Canada , Environment Canada and Energy, Mines and Resources.

The testing consisted of batch scale runs followed by pilot plant scale operation. Over 350 tonnes of desand sludges, and tank sand were processed in the pilot scale operations. Four feeds were tested; MOBIL Kitscoty field tank sand, MOBIL Celtic, ESSO Cold Lake, and BP Wolf Lake desand pit sludges.

The tank sand was processed directly as received, being dry enough to handle. The desand sludges were pre-mixed with measured amounts of recycled, processed ATP solids to allow ready handling of the waste.

Processing by the ATP produced an average clean product oil recovery (Butanes and heavier) of 61 weight% of the feed oil content, as light oil (S.G. .863, 32.5°API).

The flue gas emissions met Environment Canada guidelines as presented in Table 3. The metals discharge were typically one half or less than the emissions criteria.

The solids effluents leachate analyses showed non-detectable levels of oil and grease with low to less than detectable levels of metals, as presented in Table 4. Chlorides and sulphates levels in the leachate were at levels of 120 mg/l or less, well within surface run off criteria.

2) Invert drilling mud cuttings. Invert drilling muds are comprised of major amounts of diesel oil. Most of the mud is recovered from the cuttings and recycled in the drilling operation. The settled cuttings can still contain significant levels of oils. Nearly 120 tonnes of these cuttings were obtained for testing at the pilot scale.

The cuttings, as received, were contained by a berm, which was subsequently treated with the feed. A full range of batch, pilot and commercial unit operations, in 1988 and 1989, proved oil removal capabilities, with more than 60% of the oil being recovered as butane and heavier liquids.

The flue gas particulate emission was less than half the allowable criteria, as presented in Table 3. The solids effluent leachate data showed low levels of chlorides, sulphates and metals as presented in Table 4.

3) Production and Exploration wastes. Production and exploration wastes were acquired in 1989, with oil and water content in excess of 20 weight% each. This material was mixed 2:1 with recycled residual solids to bring the liquids content to a maximum of 14% total. Over 90 tonnes of mixed wastes feed was processed in the commercial 10 tph plant.

The flue gas particulate discharge was especially low, with metals emissions being 2 to 1000 times less than the criteria, as may be seen in Table 3. Leachate data on solids effluent, presented in Table

4, showed values near the detection limit, with metals concentrations being low or less than detectable.

4) Refinery wastes. A sample of material from the clean-up of a decommissioned refinery was received for test operation in 1986. This was processed in the pilot plant 4.5 tph facility. A second major sample from another site was received in 1989. This second sample was in excess of 150 tonnes and was processed in the commercial 10 tph plant.

The flue gas particulate discharge was less than required levels with metals emissions being as much as 1000 times less than the criteria. Leachate data on solids effluent showed oil and grease levels of 0.7 mg/l or less, with metals concentrations being low or less than detectable. Additional analyses showed monocyclic and polycyclic aromatic hydrocarbons at or below detection limits in the solids residue leachate. The flue gas and solids leachate data may be seen in Tables 2 and 3.

5) PCB contaminated soils. Most situations, in which solids have been contaminated with PCBs, involve levels less than 1 percent (10000 ppm). The ATP has processed as much as 16000 ppm of PCB contaminated solids. Environment Canada guidelines state that no commercial treatment facility shall release solids with levels of PCBs in excess of 0.5 mg/kg (0.5 ppm dry basis).

The ATP separates PCBs from the host solids, concentrating the PCBs in the oil and liquid products, returning nearly all of the solids as environmentally acceptable landfill material with less than 0.1 mg/kg of PCB.

In the two specific PCB test runs, made in 1988, approval was acquired, from the Alberta Environment, to artificially contaminate (spike), an oil sand already containing 2 weight% oil.

In the first run, PCB was added to a 7000 ppm level. Due to the success of the first run, a second run was approved with PCB spiking of 1.6% or 16000 ppm.

The first run produced solids with less than detectable PCBs (less than 0.1 ppm), and a Destruction or Removal Efficiency (DRE) better than "six nines" or 99.9999%. The second run, with feed PCB levels of 16000 ppm produced solids measured at 0.1 ppm PCB and a DRE of 99.9999%.

Nearly 100% of the PCBs in the feed reported to the condensed oil product, with 82% appearing in the heaviest fractions and 8% in the lightest overhead oils. The heavy oil had an average PCB concentration of 200000 ppm (20%), and the light oil containing less than 25000 ppm (2.5%).

This reduced the hazardous waste mass by over 96%. Less than 4% of the original contaminated soil required appropriate destruction at an approved facility.

ATP CAPACITIES AND TREATMENT COSTS

Solutions to oily waste treatment need to address the limited volumes of wastes produced or available at any one particular site. Oily waste is generally produced in low quantities which discourage permanent facility placement. In these situations, a plant which could be readily moved from site to site, with project quantities of about 7000 tonnes, minimum, would be feasible. If a high density industrial area produces low quantities, but continuous amounts of treatable products, then a fixed treatment centre could be feasible.

Figure 3 presents ATP costs for plant configurations up to 10 tph. The costs are based on year-round operation, 24 hours per day. The plant would be a full service facility, including disposal costs for products, such as deep well injection of water product.

Two curves are displayed, representing costs for two distinct capacities of plants. The two ranges overlap, indicating the cost benefits of maximizing the use of a smaller plant (nominally 5 tph), instead of underutilizing a larger capacity plant (nominally 10 tph).

The wide band of each range reveals the variability in costs, considering such factors as fixed or transportable plants, and the feed quality. Mobilization and de-mobilization of a plant is an increased cost over a fixed plant scenario. Additional factors include the feed characterization; increased liquid content, possibly restricting or increasing the rated capacity.

Costs would be higher for projects of intermittent feed supply, or frequent requirements for relocating the plant.

With proper sizing and project management, treatment and disposal costs should be under $125 Canadian per tonne.

ADDITIONAL READING

1. R.M. Ritcey, "The AOSTRA Taciuk Process — Portable Pyrolysis Technology System for Remediation of Organic Wastes", Air and Waste Management Association, International Specialty Conference, Banff, Alberta, October ,1989.
2. L.R. Turner, "Treatment of Oilsands and Heavy Oil Production Wastes Using the AOSTRA Taciuk Process", Conference on Oil Field Production Wastes, Calgary, Alberta, May 1989.

TABLE 1
FEED MATERIALS TESTED

FEED MATERIAL	BATCH UNIT	PILOT (4.5 tph)	COMMERCIAL (10 tph)
RESOURCE PROCESSING			
Low grade Oil Sands	•	•	
Average grade Oil Sands	•	•	
High grade Oil Sands	•	•	
U.S. Low grade Oil sand/shale	•	•	
U.S. High grade Oil Shale	•		
Utah Oil Shale	•	•	
Malagasy Oil Sands	•	•	
Australian Oil Shale	•	•	
Lloydminster Heavy Oil	•	•	
Rubber Tires	•	•	
Brazilian Oil Shales	•		
New Zealand Peat Moss	•	•	
Israeli Oil Shales	•		
New Brunswick Oil Shales	•		
WASTE PROCESSING			
Refinery Cleanup Wastes	•	•	•
Refinery Alkylation Wastes	•		
Coal Tar Residues	•		
Invert Drill Mud Cuttings	•	•	•
Oil Field Desand Sludges	•	•	•
Oil Field Tank Sand	•	•	
PCB Oily Waste	•	•	

GENFEED

TABLE 2
ATP WASTE PROCESSING FEED CHARACTERISTICS

TESTING UNIT -	MOBIL Tank Sand Pilot	MOBIL Desand Sludges Pilot	ESSO Desand Sludges Pilot	BP Desand Sludges Pilot	Drill Mud Cuttings Pilot	Prod & Explor Wastes 10 tph	Refinery Wastes 10 tph	PCB Soil Pilot
PROCESSOR FEED								
Mixed feed Oil/Grease	8.3	7.6	5.8	5.9	15.3	7.0	0.3	2.7(1.9)
Mix feed Water %	8.3	9.6	10.2	9.5	7.3	7.0	10.9	2.4(2.8)
Mix feed Solids %	83.4	82.8	84.0	84.6	77.4	86.0	88.8	94.1(93.7)
PCB in feed %								0.7(1.6)
WASTE ONLY CONSTITUENTS								
Oil/Grease	18.0	13.6	12.3	17.4	15.3	21.2	0.5	
Water %	13.3	14.0	17.2	20.2	7.3	23.0	14.0	
Solids %	68.6	72.4	70.5	62.5	77.4	55.8	85.5	
Mix feed % waste	46	56	47	34	100	33	63	
Mix feed % add sand	54	44	53	66	0	67	37	

NOTE: PCB soil processing runs #1 (#2)

GENFLUE

TABLE 3
ATP WASTE PROCESSING FLUE GAS CHARACTERISTICS

TESTING UNIT –		MOBIL Tank Sand Pilot	MOBIL Desand Sludges Pilot	ESSO Desand Sludges Pilot	BP Desand Sludges Pilot	Drill Mud Cuttings Pilot	Prod Explor Wastes 10 tph	Refinery Wastes 10 tph	PCB Soil Pilot	EMISSIONS CRITERIA ENV CANADA
PARTICULATES	mg/m^3	____	____	____	____	18.9	3.238	17.655	____	50
METALS	mg/m^3									
	Aluminum	1.925	6.2	____	____	____	0.0431	–	____	
	Arsenic	____	____	____	____	____	0.0009	–0.0031	____	5
	Barium	0.55	0.25	____	____	____	0.0012	1.310366	____	
	Beryllium	–0.0625	–0.1	____	____	____	0.00001	–	____	
	Boron	1.025	10.5	____	____	____	0.003	–	____	
	Cadmium	0.175	–0.1	____	____	____	0.00092	0.0035	____	0.2
	Calcium	9.825	9.4	____	____	0.116	0.364	–	____	
	Chromium	0.3025	0.3	____	____	____	0.00178	0.007066	____	1
	Cobalt	–0.1	–0.1	____	____	____	0.00124	0.0192	____	1
	Copper	0.275	–0.1	____	____	____	0.00455	0.001733	____	5
	Iron	6.975	9.9	____	____	____	0.146	–	____	
	Lead	1.4	1	____	____	____	0.244	0.007033	____	5
	Lithium	–0.075	–0.1	____	____	____	–	–	____	
	Magnesium	2.85	3.25	____	____	0.024	0.0728	–	____	
	Manganese	0.575	0.25	____	____	____	0.00756	–	____	5
	Mercury	____	____	____	____	____	0.109	0.0008	____	0.2
	Molybdenum	0.5125	–0.1	____	____	____	0.0119	0.008966	____	
	Nickel	0.605	0.67	____	____	____	0.0115	0.963766	____	1
	Potassium	0.725	2	____	____	0.033	0.0117	–	____	
	Selenium	____	____	____	____	____	–	–0.0025	____	1
	Silver	____	____	____	____	____	–	–0.0005	____	
	Silicon	2.2	0.9	____	____	____	0.0857	–	____	
	Sodium	–5	–5	____	____	0.235	0.101	–	____	
	Strontium	0.1	0.1	____	____	____	0.00168	–	____	
	Tin	____	____	____	____	____	–	0.274433	____	
	Titanium	0.15	0.15	____	____	____	0.0027	–	____	
	Vanadium	0.1	–0.1	____	____	____	0.00074	0.0037	____	5
	Zinc	0.3	–0.1	____	____	____	0.0158	0.760266	____	5
HCL	ug/m^3	____	____	____	____	____	1681	6	____	75000
PCB	ug/m^3	NA	NA	NA	NA	NA	NA	NA	4.2(2.4)	
	DRE %								99.9999(*)	99.9999

MAH's	ug/m^3								
	Benzene	____	____	____	____	____	84.7	69.0	____
	Ethyl Benzene	____	____	____	____	____	0.41	2.6	____
	Toluene	____	____	____	____	____	3.56	13.1	____
	Styrene	____	____	____	____	____	–	0.6	____
	Xylene	____	____	____	____	____	1.22	18.1	____
PAH's	ug/m^3								
	acenaphthene	–0.5	–0.5	–0.03	–0.03	____	–	–0.091	____
	acenaphthylene	–0.5	–0.5	–0.03	0.08	____	–	0.090	____
	anthracene	1.4	–0.5	17.2	–0.03	____	–	0.110	____
	benzo(a)anthracene	–0.5	–0.5	–0.03	–0.03	____	–	–0.091	____
	benzo(a)pyrene	–0.5	–0.5	–0.03	–0.03	____	54.3	–0.091	____
	benzo(b)fluoranthene	–0.5	–0.5	–0.03	–0.03	____	–	–0.091	____
	benzo(k)fluoranthene	–0.5	–0.5	–0.03	–0.03	____	–	–0.091	____
	benzo(g,h,i)perylene	–0.5	–0.5	–0.03	–0.03	____	–	–0.091	____
	chrysene	12.4	–0.5	78.5	–0.03	____	–	–0.091	____
	dibenzo(a,h)anthracene	–0.5	–0.5	–0.03	–0.03	____	–	–0.091	____
	fluorene	–0.5	–0.5	–0.03	3.43	____	–	–0.091	____
	fluoranthene	–0.5	–0.5	–0.03	16.2	____	–	0.160	____
	indeno(1,2,3,c,d)pyrene	–0.5	–0.5	–0.03	–0.03	____	–	–0.091	____
	naphthalene	–0.5	–0.5	–0.03	–0.03	____	1098	0.596	____
	phenanthrene	9.8	–0.5	107.3	3.83	____	–	0.537	____
	pyrene	–0.5	–0.5	–0.03	–0.03	____	–	0.110	____

NOTE: (–nn) indicates 'value less than detection limit of nn'
(–) indicates 'NOT DETECTED'
(____) indicates 'not tested for'
(NA) indicates 'Not Applicable'

GENTL2

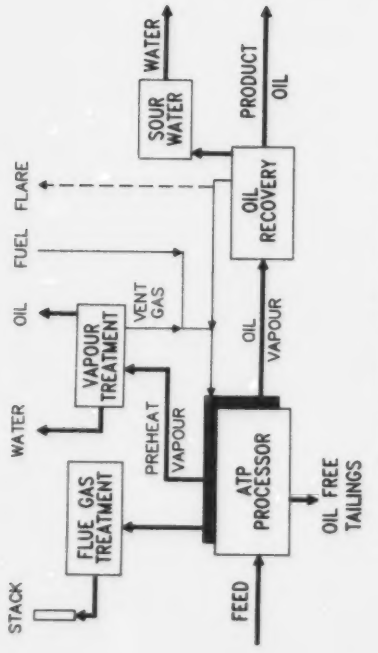
TABLE 4

ATP WASTE SOLIDS RESIDUE LEACHATE CHARACTERISTICS

TESTING UNIT –	MOBIL Tank Sand Pilot	MOBIL Desand Sludges Pilot	ESSO Desand Sludges Pilot	BP Desand Sludges Pilot	Drill Mud Cuttings Pilot	Prod Explor Wastes 10 tph	Refinery Wastes 10 tph	PCB Soil Pilot	CRITERIA Env Canada
Oil/Grease mg/l	–0.5	–0.3	–0.1	–0.1	____	0.3	0.7	____	
Specific Cond. umho/cm	____	____	____	____	180	____	____	____	
MAJOR CATIONS mg/l									
Chloride	58.8	119.5	14.7	10.3	165	1340.1	____		
Sulphate	55.1	117.8	77.8	73.6	109	129824	____		
METALS mg/l									
Aluminum	2.80	3.93	3.94	2.71	____	0.15	____	____	
Arsenic	____	____	____	____	____	____	____	____	5
Barium	0.19	0.23	0.40	0.22	____	0.09	____	____	100
Beryllium	0.000	0.000	0.000	0.000	____	–0.001	____	____	
Boron	0.19	0.21	0.53	0.24	____	1.9	____	____	500
Cadmium	0.002	0.000	0.002	–0.001	____	–0.001	0.03	____	0.5
Calcium	715	946	1875	1477	96	600	____	____	
Chromium	0.003	–0.001	0.009	0.002	____	–0.001	0.12	____	5
Cobalt	0.002	0.003	0.012	0.008	____	–0.001	____	____	
Copper	0.014	0.017	0.091	0.080	____	0.092	0.03	____	
Iron	0.65	1.07	1.25	0.87	____	–0.01	–0.01	____	
Lead	0.000	–0.001	0.010	0.041	____	–0.01	____	____	5
Lithium	0.006	0.006	0.018	0.013	____	0.007	____	____	
Magnesium	70	104	185	128	0.15	80.4	____	____	
Manganese	2.35	4.25	4.50	3.62	____	2.17	____	____	
Mercury	____	____	____	____	____	____	–0.0008	____	0.1
Molybdenum	0.053	0.059	0.155	0.097	____	0.01	____	____	
Nickel	0.027	0.041	0.068	0.039	____	0.024	–0.05	____	
Potassium	4.28	6.38	7.92	7.37	5	6	____	____	
Selenium	____	____	____	____	____	____	____	____	1
Silver	____	____	____	____	____	____	____	____	5
Silicon	24.1	23.4	37.0	21.2	____	21.7	____	____	
Sodium	19.03	13.55	8.66	5.64	3.5	____	____	____	
Strontium	1.32	1.25	1.78	2.03	____	0.47	____	____	
Tin	____	____	____	____	____	____	____	____	
Titanium	–0.001	–0.001	–0.001	–0.001	____	–0.001	____	____	

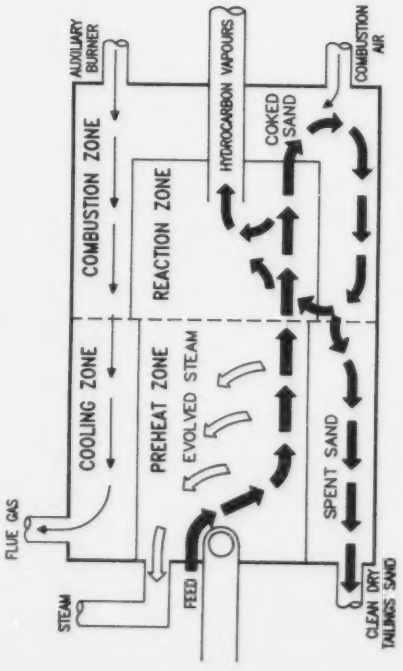
	Vanadium	0.013	0.013	0.053	0.044	____	0.009	____	____
	Zinc	0.228	0.125	0.462	5.568	____	0.29	0.07	____
PCB	mg/l	____	____	____	____	____	____	____	____
MAH's	mg/l								
	Benzene	____	____	____	____	____	0.07	-0.002	____
	Ethyl Benzene	____	____	____	____	____	-0.01	-0.002	____
	Toluene	____	____	____	____	____	0.01	0.004	____
	Styrene	____	____	____	____	____	-	-0.002	____
	Xylene	____	____	____	____	____	-0.01	0.006	____
PAH's	ug/l								
	acenaphthene	____	____	____	____	____	-	-1.0	____
	acenaphthylene	____	____	____	____	____	-	-1.0	____
	anthracene	____	____	____	____	____	-	-1.0	____
	benzo(a)anthracene	____	____	____	____	____	-	-1.0	____
	benzo(a)pyrene	____	____	____	____	____	-	-1.0	____
	benzo(b)fluoranthene	____	____	____	____	____	-	-1.0	____
	benzo(k)fluoranthene	____	____	____	____	____	-	-1.0	____
	benzo(g,h,i)perylene	____	____	____	____	____	-	-2.0	____
	chrysene	____	____	____	____	____	-	-1.0	____
	dibenzo(a,h)anthracene	____	____	____	____	____	-	-1.0	____
	fluorene	____	____	____	____	____	-	-1.0	____
	fluoranthene	____	____	____	____	____	-	-1.0	____
	indeno(1,2,3,c,d)pyrene	____	____	____	____	____	-	-2.0	____
	naphthalene	____	____	____	____	____	-	-1.0	____
	phenanthrene	____	____	____	____	____	-	-1.0	____
	pyrene	____	____	____	____	____	-	-1.0	____

NOTE: (-nn) indicates 'value less than detection limit of nn'
(-) indicates 'NOT DETECTED'
(_____) indicates 'not tested for'



AOSTRA TACIUK PROCESS (ATP)

FIGURE 1



ATP PROCESSOR
INTERNAL PROCESS FLOWS

FIGURE 2

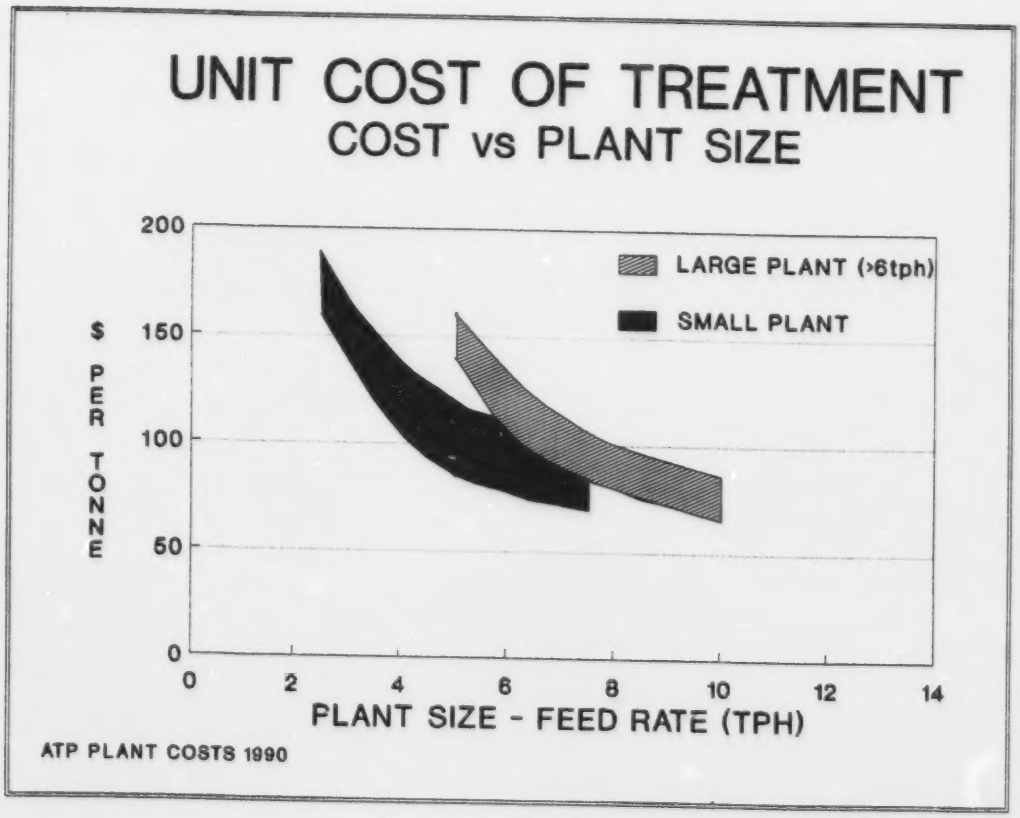


FIGURE 3

Disposal Of Tailings Sludge In Overburden Waste Dumps

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Abstract. Syncrude, with the support of AOSTRA, has developed a technique that may be of use in dewatering significant volumes of tailings pond sludge on a operating basis. The Clearwater Formation clay shale overburden in the mining area is very dry, and has an extremely high plasticity. By mixing specified volumes of sludge to the clay shale, an engineered clay of known strength can be produced. This new material can be contained within a stable overburden waste dump which can be designed and constructed to current safety standards.

Both laboratory and field tests to evaluate strength relationships and mixing methods of clay shale/sludge mixtures are described.

INTRODUCTION

In the production of synthetic crude oil from oil sand using bitumen extraction by the hot water flotation method, large quantities of liquid clay suspension known as tailings sludge are produced. Unlike the coarser tailings sand, this sludge remains a liquid and poses problems with regards to its ultimate disposal.

Syncrude's Lease Development Plan identifies the final storage of tailings sludge as contained within the mined out pits in a semi-liquid form. This sludge consolidates very slowly and consequently will remain as a semi-liquid during the permit life. Other waste products, such as overburden and tailings sand are disposed of separately; placed in waste dumps and reclaimed as dry land.

AOSTRA supported studies over the past two years indicate that Syncrude and other oil sand operators have a potential opportunity to solidify or dewater large volumes of sludge by mixing it with overburden and then incorporating the new material into stable waste dumps. Approximately 2130 Mm^3 of overburden have to be stripped during the current permit life (year 2018) of the mine and the expected sludge volumes will total 680 Mm3 by this time. With the potential to solidify a large volume of the sludge product, a better use could be made of the mined out areas by increasing the volume of overburden deposited in pit.

BACKGROUND

The possibility of absorbing sludge in the overburden waste dumps has been considered by Syncrude technical staff since 1982 as a component part of a scheme to remove overburden using dredging and pipeline techniques. With the support of AOSTRA, the dredging method was field tested in 1985/86 and using this sludge as the hydraulic transport medium, overburden deposits were produced which were classified as very soft clay. Up to 0.5 m^3 of sludge had been absorbed by every 1 m^3 of clay shale excavated (Lord, *et. al.*, 1986, Coward, *et. al.*, 1986, Lord and Isaac, 1989). Dredging was not pursued but the possibility of absorbing sludge in a conventional waste dump by incorporating clay generated by mixing controlled namo unts of sludge with overburden remained an active technical investigation.

A site visit to the Hambach Mine, Germany in 1985, and a review of published literature indicated that naturally occurring soft clay can be incorporated into stable waste dumps on a routine basis utilizing spreader placement methods, (Henning, 1986). By careful planning, better quality material is utilized to construct the ribs of containment cells into which soft clay is deposited, i.e.; the poldering technique. The dump is designed and constructed such that overall stability is maintained and trafficability of mobile equipment is possible on the surface of each lift.

Based on this knowledge, Syncrude Research staff embarked on a laboratory testing program to establish the relationship between dump strength and volume of sludge absorbed. Utilizing a spreader dump designed as part of the Syncrude Expansion Studies, a project group was formed to provide a preliminary assessment of the stability for a dump incorporating overburden/sludge polders. The encouraging results from this study added to the impetus to undertake a comprehensive overburden/ sludge laboratory and field program which has received active support from AOSTRA.

CONCEPT

A clay can exist in three states depending on its water content (Figure 1). It is solid when dry and upon the addition of water, passes through the plastic to the liquid state. The water content[1] at the boundaries between adjacent states are termed Plastic and Liquid Limit.

In the Syncrude mining area, part of the overburden consists of a clay shale known as the Clearwater Formation. Each year the proportion of this unit is increasing such that by the year 2000 it will account for about 80% of the total overburden stripped. From a geotechnical perspective, the Clearwater Formation is described as a dense heavily over-consolidated clay shale with an extremely high plasticity. The combined clay/silt content is close to 100%. The average Liquid Limit is 109% with values over 200 recorded (Figure 2). The average in situ water content is 20% which is 4% below the Plastic Limit (24%) i.e., it is very dry (Figure 2).

A remarkable feature when compared to other clays, is the wide range of water content which can exist between the Plastic Limit at 24% and the Liquid Limit at 109%. The nature of the Clearwater Formation clay shale is such that its ability to absorb water and still remain in the plastic range far exceeds that of most other clays.

At the Hambach Mine, Germany, naturally occurring soft clays are incorporated into the waste dump utilizing spreader placement techniques on a routine basis. Dump construction comprises three elements (Figures 3 and 4):

- Construction of ribs with better quality material to form a containment cell.
- Infilling the containment cell with naturally occurring soft clay.
- Addition of a capping layer to support the spreader and other equipment.

For Syncrude's application, the possibility exists to follow a similar procedure with the soft clay being produced by mixing sludge with clay shale. The in-pit or out-of-pit dump would be designed and constructed to maintain short and long term stability and permit operation of the equipment on top of the polders. Studies to date have concentrated on utilizing a spreader or trucks to deposit the dry overburden for the ribs and polders, but the possibility of pipelining overburden with sludge as the carrier fluid to infill the polders is also being considered.

CONCEPT DEVELOPMENT- STAGE I

Concept development has comprised of:

- Detailed geotechnical characterization of the clay shale overburden.
- Laboratory determination of the clay shale absorption potential and strength/water content relationship.
- Preliminary assessment of stability of a waste dump incorporating overburden/sludge polders.

Detailed Geotechnical Characterization of the Clay Shale Overburden. Two boreholes were drilled through the overburden and were geotechnically characterized in detail. The cores were sampled at 500 mm intervals and the following measurements were made:

- Liquid Limit, Plastic Limit, Water Content
- Clay Content, Silt Content, Sand Content

One borehole was located adjacent to the North Mine and the Liquid Limit, water content and Plastic Limit profiles are shown in Figure 2. The other borehole was drilled in an area where the full thickness of Clearwater Formation occurs (south end of South West Sand Dump).

A summary of the characteristics of the clay shale units to be excavated in the North Mine area are:

	North Mine		S.W. Sand Dump	
Borehole #	Range	Average	Range	Average
Liquid Limit	46-232	109	35-212	89
Plastic Limit	17-40	24	15-37	21
Water Content	13-32	20	6-31	17
Clay Content	29-92	54	12-85	44
Silt Content	8-71	41	15-79	54
Sand Content	0-34	5	0-31	2

The results indicate the clay shale has a very low in situ water content and an extremely high plasticity range. The remarkable plasticity is further demonstrated by referring to soil mechanics text books and examining plasticity charts which indicate that a large part of Syncrude's clay shale can be off the chart!

Laboratory Determination of Strength/Water Content Relationship. In 1985 attempts were made to prepare large diameter samples of clay shale/sludge mixtures. Mature sludge was poured into the 300 mm diameter specimen former to a depth of 150 mm and a layer of clay shale lumps (50-100 mm) gently tamped into position under the sludge. The 600 mm high specimen was formed in successive layers and a 50 mm layer of sludge covered the top of the specimen which was then allowed to set for periods ranging from 1 to 9 days. It was observed that in the unconfined state the lumps absorbed sludge readily and softened to the point that at absorption times longer than a few hours, the samples behaved as a lumpy paste. In this condition the samples could not support their own weight, and the specimens could not be tested for strength in the triaxial compression cell.

[1] *In soil mechanics water content, Liquid Limit and Plastic Limit are defined as the weight of water divided by the weight of solids.*

A change in sample preparation and reduced absorption time enabled a successful test. In this case 25 mm clay shale lumps were placed in the specimen former which was transferred to the triaxial compression cell. Sludge was introduced into the specimen from the base. After 55 minutes, sludge had saturated the interlump void space to the top of the sample. The test was conducted after 1 hour, 54 minutes and the specimen failed at 6% strain with an undrained shear strength of 12.5 kPa (1.8 psi) and water content of 33%. After the test, it was observed that the clay lumps were virtually intact. Wherever the sludge had contacted the lumps, a thin layer of softened clay was evident, but the interior of the lumps appeared unaffected. The sludge filling the interlump voids appeared to have thickened to the consistency of paste. In this test the equivalent of 1 m^3 of excavated clay shale had absorbed 0.38 m^3 of mature sludge.

Because of the difficulties and costs associated with preparing and testing large specimens a series of triaxial compression tests were conducted on smaller 35 mm diameter by 75 mm long specimens which had been subsampled from a larger sample prepared in a compaction mould. In this laboratory program, testing was specified to ascertain whether distilled water, immature sludge and mature sludge produced different results with the same clay shale. The results are plotted in Figure 5. It was found that the strength data was similar at the same final water content, whether sludge or water had been added.

Data on the strength of clay shale/sludge mixes was also obtained form tube samples taken from the deposits produced in the dredging experiment in 1986. These tests were conducted on 100 mm diameter by 200 mm long samples. The results are also plotted on Figure 5.

Feasibility Study of the Concept. Using the relationship established in Figure 5, and the potential spreader dump designed for Syncrude, Hardy BBT working in association with Rheinbraun Consulting, were contracted to provide a preliminary assessment of stability for a waste dump incorporating polders. It was assumed that the overburden/sludge mixes could be produced and placed into the polders. A 1.5 factor of safety was used for the slope stability analyses.

A number of parametric studies were performed varying the size and shear strength of the polders at different elevations. The overall predicted sludge absorption potential for the Expansion Dump was around 0.2 m^3 of sludge for each 1 m^3 of clay shale excavated.

CONCEPT DEVELOPMENT - STAGE II

In consultation with AOSTRA, a detailed program was formulated to undertake the following activities:

- Review of case records of dumps with similar materials to the Athabasca region.
- Laboratory and field testing to increase data base for rib and polder material.
- Analytical work.
- Mine planning and economic assessment.

Work started in May 1988, and was completed in March 1990.

Case Records. The review of case records focused on mines utilizing spreaders to dispose of a high plastic clay shale. A worldwide search identified one mine which has a clay shale overburden similar to Syncrude's Clearwater Formation and also utilizes polder techniques to incorporate naturally occurring soft clays within the waste dump (Herbst, 1988). A further four mines were identified which excavate and dispose of clay material similar to the Clearwater Formation.

The review indicated that the limiting height of the spreader deposited clay shale was in the 12-18 m range.

Limiting Height. A key parameter for the design and construction of a waste dump utilizing a spreader is the limiting height, which is the height at which continued overburden discharge results in only a minor increase in the dump height, but the onset of bulging in the lower part of the slope (Figure 6). Limiting height varies from material to material and is a function of a number of factors such as:

- Depth of burial and saturation prior to excavation.
- Mineralogy of the lump particles and plasticity range.
- Lump surface and internal strength properties.
- Lump surface and internal water content at the dump.
- Lump size, density and angularity at the dump.

The rate of discharge, drop height and slewing action may also have an effect.

Up to the limiting height, the clay shale lumps behave as an unsaturated pseudo-granular deposit. As the dump increases in height, the lump to lump contact points at the lower levels are over stressed. The crushed material infills between the lumps decreasing the air filled void space. Eventually a saturation point is reached in the lower part of the dump wherein an increase in dump height results in a pore pressure response. The reduced effective stress acting between the clay lumps in the lower part of the dump results in bulging until the shearing reduces the pore pressure and dump is stable again.

Bulging should be prevented to minimize unplanned operational changes during construction and to maintain the dump design geometry. Based on a limited laboratory test program and review of operations disposing of similar overburden, the Expansion Spreader Study report recommended that

for planning purposes, a limiting height of 12 metres be used for clay shale overburden. A more definitive value for the limiting height was required so that the mine plan and polder volumes could be optimized. Also, a higher value would allow the flexibility to construct the dump with less passes and thereby potentially reduce operating costs. Site specific limiting height data was one of the main objectives of conducting the 1988 field test.

Field Testing. The field test was divided into two phases. Phase 1 provided insight into the dump geotechnical properties, and consisted of:

- Strength testing of polder material at different sludge to overburden ratios.
- Evaluation of Limiting Height.
- Assessment of sludge infiltration into an overburden rib.

Phase 2 provided insight into potential mixing methods, and consisted of:

- Assessment of overburden/sludge mixing utilizing Operations' scale truck/dozer equipment.
- Experimental scale assessment of overburden/sludge mixing utilizing spray technique.
- Experimental scale of overburden/sludge mixing utilizing a backhoe to simulate spreader placement of lumps into sludge.

OVERVIEW OF PHASE 1

Phase 1 field testing was conducted at a site located west of Syncrude's Tailings Pond during August and September 1988 with followup of studies in June 1989.

Clay Shale/Sludge Mixes. In the laboratory the strength/water content relationship had been developed using standard laboratory equipment. This required lumps to be broken down to size suitable for the apparatus. In the field test it was possible to use natural clay lumps which were of much larger size and realistic shape. Eight test pits were constructed of which the first acted as a control, containing only clay shale lumps with no addition of sludge. Five 5 m x 5 m x 3 m deep pits were utilized to provide strength/water content data. The volume of sludge added was varied from pit to pit so that a range of water contents was achieved. A backhoe was used to mix the clay shale and sludge in the pit (Figure 7).

To gain further insight into these mixing processes, a pit was filled to a depth of 1 m with sludge and then lumps added to simulate a spreader discharge. Initially, sludge filled the interlump voids and over time water was absorbed into the lumps. Another pit modelling the spraying process was built up in alternating layers of 300 mm clay shale followed by 100 mm sludge.

In situ vane and cone tests were conducted in the pits to give an indication of shear strength. Undisturbed tube samples were taken for water content determination and other geotechnical laboratory tests. This testing was done after one week, one month and ten months to monitor change over time, particulary with respect to water content.

The relationship between water content (sludge content) and strength is shown in Figure 8.

Seepage of sludge into the unsaturated ribs was assessed in another pit created against the clay shale cone (described later). Seepage over time was monitored with piezometers and the sludge pit was pumped out ten months later in June 1989. A trench was excavated to measure the extent of softening which was found to be about 2 m.

Bearing Layer. The purpose of this part of the field program was to evaluate the thickness of the bearing layer required to support equipment on top of the polder material. The feasibility study assumed it to be 5 m of "dry" clay shale. A backhoe with a 700 mm track width was placed over the "polder" which had a 1 m thick trafficability surface and deformation was observed. This procedure was repeated with bearing layer thickness of 700, 400 mm and 100 mm. It was found that under static conditions the lowest strength polder was able to support the backhoe which exerted a ground pressure of 52 kPa.

Limiting Height. A contract was awarded to TBO Contracting Ltd. to provide a portable conveyor (Pioneer manufactured by Portec) having a capacity of 450 loose m^3/h and a discharge height of 10 m. For the test, a cone height of 16 m was specified which was achieved by excavating a 6 m deep pit and raising the conveyor on a 2 m high ramp. To ensure continuous delivery of clay shale lumps a stockpile had been constructed prior to the start of the test.

The cone was constructed over a seven day period in August 1988 (Figure 9). A weightometer on the conveyor belt provided data on the mass and regular profile surveys provided the volume which together gave an indication of cone density. Piezometers and total pressure cells in the base of the cone were monitored during and after the test. A borehole was augered into the pile to take tube samples which were tested in the laboratory.

The cone reached a height of 16 m without any sign of lower slope bulging, which suggests the limiting height exceeds 16 m.

In June of 1989 the cone was excavated to conduct in situ density tests. During this work it was found that the interior of the cone had reached temperatures as high as 73°C. Laboratory studies indicated the heat resulted from oxidation of iron sulphide to sulphate which was promoted by the high porosity at the base of the cone.

OVERVIEW OF PHASE II

In the second field program in October 1989, three mixing methods were assessed at a site located at the south end of the mine.

Truck/Dozer Mixing. A large polder, 50 x 65 x 8.5 m deep, was formed into which 14,000 m^3 of sludge was discharged. 170T trucks delivered overburden from an operating face at production rates. The overburden was end dumped at the edge of the polder and then dozed into the sludge (Figure 10). The test was designed to provide a 4 m thick bearing layer enabling the heavy trucks to operate over the newly created overburden/sludge polder material (Figure 11). The polder volume was about 15,000 m^3 which was overlain by a 12,600 m^3 bearing layer. In the polder, the sludge to overburden ratio ranged from less than 0.1 to 0.4. The lower values will be more typical of a commercial scale operation.

Spray Technique. To evaluate the feasibility of sludge spray, 170 T trucks delivered the overburden which was end dumped and pushed by dozer over the dump crest. A hydroseeder was utilized to spray the advancing overburden face (Figure 12).

A test volume of 4400 m^3 was generated with an average sludge to overburden ratio of about 0.1. This test was intended to provide insight into the technique.

Spreader Technique. Overburden was delivered to the edge of the sludge overflow pit. A backhoe was utilized to drop overburden into a sludge pool thereby providing insight into the spreader technique (Figure 13). Three "islands" were formed with a combined volume of 4900 m^3 and an average sludge to overburden ratio of about 0.1.

LABORATORY STUDIES

Infiltration Tests. A number of methods to mix sludge with overburden lumps are envisioned. One method calls for clay shale lumps to be discharged into a polder containing sludge. The sludge volume must be sufficient for the interlump void spaces to become totally filled. The volume of sludge which infiltrates into the unsaturated clay shale ribs should be known so that the loss can be allowed for when filling the polder. Otherwise a sludge deficiency will result in a lower overall sludge absorption ratio. Also, the properties of the rib will change upon infiltration and absorption of sludge. This extent of saturation needs to be estimated so that the softened zone around the polder can be allowed for in the dump design.

During the stacker operation larger lumps readily rolled down the cone to form a bed of coarse material. As the cone grew in height, the base extended over this material and a zone of macro-porosity was created. While finer material would fill in much of the void space it was unclear as to what extent zones of macro-porosity remain and provide conduits for sludge seepage.

A field test utilizing a sludge pit against the cone has been described in an earlier section. Laboratory studies were also conducted utilizing 300 mm diameter by 1.4 m long cylinders which were filled with overburden at different densities. A layer of sludge was placed on top of the overburden and the infiltration rate measured. It was found that at densities typical of rib material, infiltration will be less than a metre.

Triaxial Testing. Unsaturated undrained triaxial compression tests were conducted on higher plastic material (Liquid Limit 150%) to broaden the data base of design information for rib material. The results indicated the strength parameters for higher (LL=150%) and lower (LL=75%) plastic clay shale were similar.

Triaxial compression strength tests were conducted on mixtures of higher plastic overburden and sludge to broaden the data base for polder material. It was found that for a specific polder strength, more sludge could be added to the higher plastic material (Figure 8).

BEARING LAYER STUDY

The polder itself would not normally be strong enough to support heavy equipment and a capping or bearing layer must be provided. The thickness will depend on:

- type of equipment
- bearing layer material
- strength of underlying polder.

A contact was awarded to Hardy BBT in Edmonton to determine the thickness of bearing layer required to support spreader equipment and 170T haulage trucks located above polders of varying strengths. The study utilized data from plate bearing tests on the Phase I test pits, triaxial compression tests at lower stress levels and finite element numerical modelling. The results were analyzed to produce design charts. The study indicated that for typical strength polders, a 3 m thick bearing layer would be adequate. This was confirmed during the 1989 field test.

MINE PLANNING AND ECONOMICS

A preliminary economic assessment was conducted for three schemes which could be adapted to the Syncrude mine. These were:

- truck/dozer
- spreader
- pipeline

The results indicate that at the Syncrude mine, some

sludge could be disposed of in a dry landscape environment thereby reducing the ultimate volume of liquid sludge. Projected costs to the end of the current operating permit, of achieving this disposal option, are approximated at close to one billion dollars.

CONCLUSIONS

The disposal of overburden mixed with tailings sludge makes use of the very dry nature of the overburden material type, which has the ability to absorb significant quantities of sludge and still maintain an acceptable strength.

This disposal option, while yet to be engineered and evaluated on a commercial scale, does offer an alternate scheme for long term sludge disposal.

Syncrude Research with the support of AOSTRA, has met one of its goals to develop new technology enabling the disposal of sludge in a manner more acceptable for long term reclamation.

ACKNOWLEDGEMENTS

The authors would like to thank AOSTRA for support of this project. The helpful advice of their colleagues during the project and preparation of this paper is acknowledged, in particular, Mr. B. Isaac and D.W. Mimura. Permission of AOSTRA and Syncrude Canada Ltd. to publish this paper is also gratefully acknowledged.

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TABLE 1. SUMMARY OF MINES

MINE	OVERBURDEN	EQUIPMENT	DUMPING DETAILS
Air Laya, Indonesia	Soft/sticky clays and dense clay/claystone/ shale LL - 73 (avg) up to 99 PL - 25 (avg) WC - 20 (avg)	2 PWH spreaders with 60 m long discharge booms	Low dump - 15 m High dump - 15 m Polder soft clays.
Loy Yang, Australia	Clay, soft and sticky clay LL - 35-70 (typical avg) up to 137 PL - 20-30 (typical avg) WC - 15-40 (typical avg) Water content above plastic limit.	1 spreader with 50 m long discharge boom	Low dump - 18 m Limiting height 12-15 m. 10 m also reported. Dump movement part of design.
Puentes, Spain	Clay LL - 50 (avg) up to 68 (avg) for one unit PL - 28 (avg) WC - 33 (avg)	5 Spreader some with 102 m long discharge boom	Low dump - 12 m High dump - 12 m Instrumentation in dumps.
St. Barbara, Italy	Dense clay LL - 80 (avg) up to 98 PL - 48 (avg) WC - 48 (avg)	3 Spreaders	Low dump - 12 m High dump - 9 m Instrumentation in dumps. Limiting height around 18-20 m.
Merkur, Czechoslovakia	Dense clay, claystone.	Spreaders with 80 m long discharge boom	Low dump -10 m High dump - 10 m

FIGURE 1

DEFINITION OF TERMS

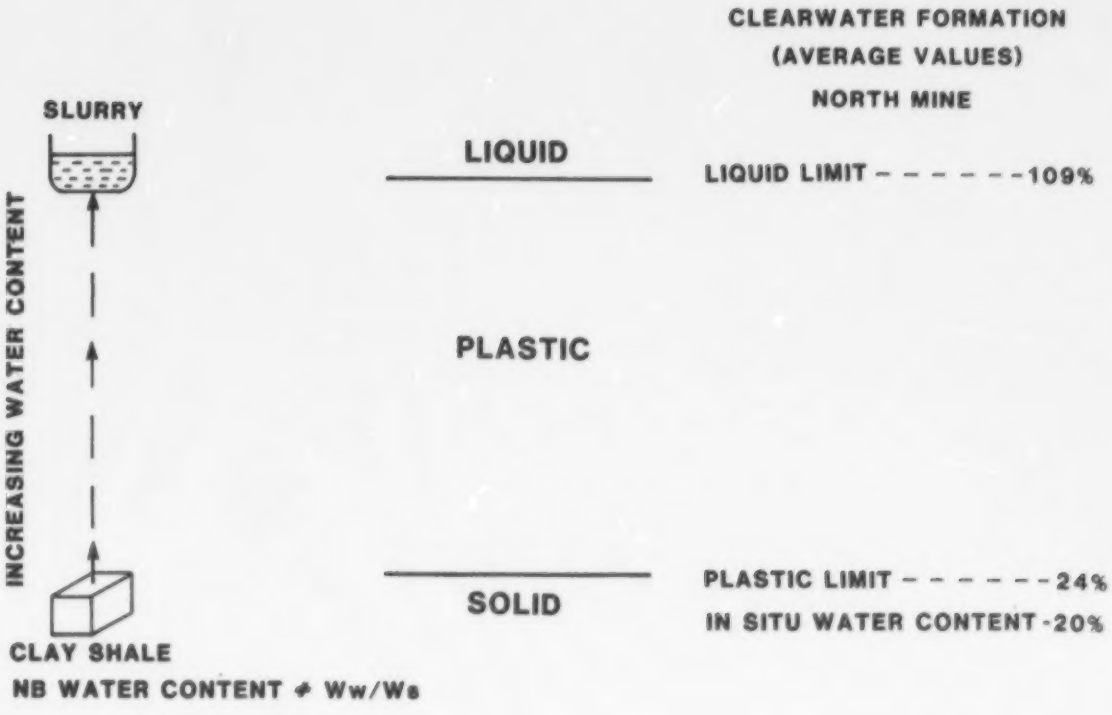


FIGURE 2

CHARACTERIZATION OF CLEARWATER FORMATION

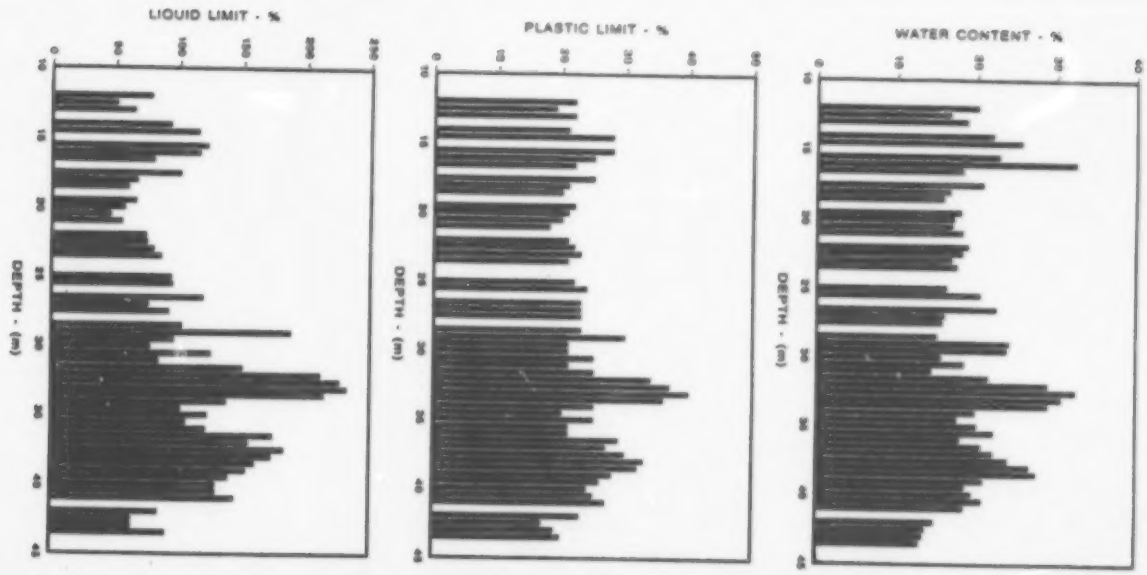


FIGURE 3

SCHEMATIC OF POLDER TECHNIQUE

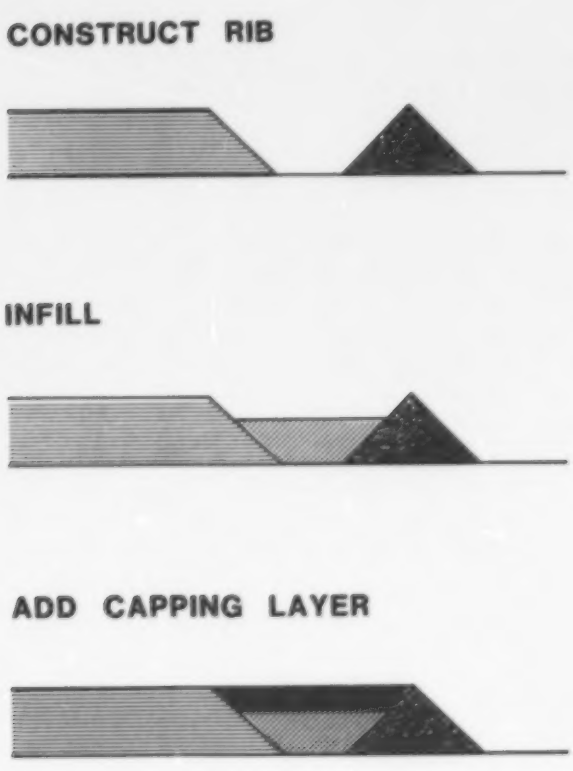
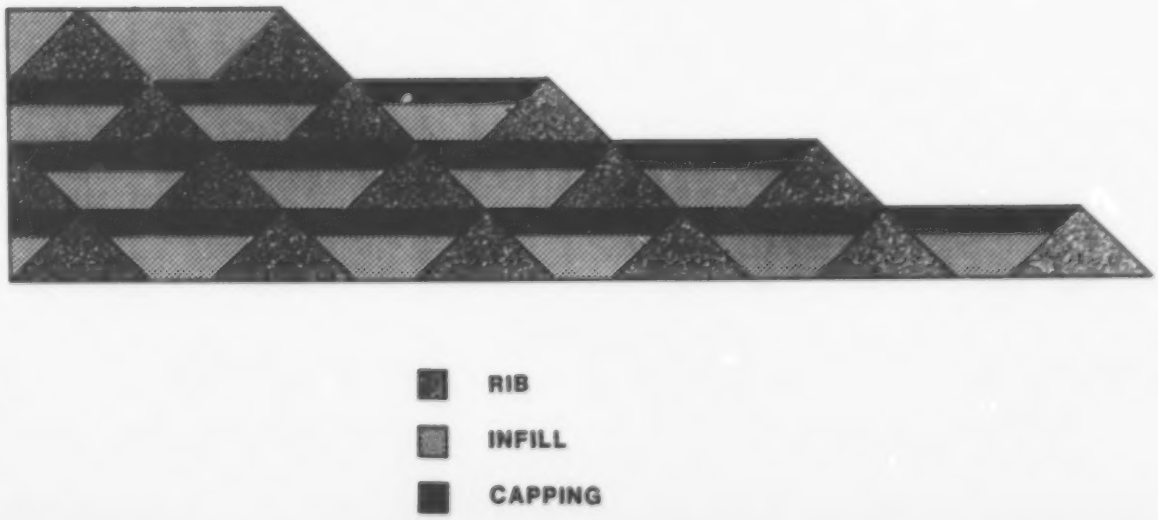


FIGURE 4

SCHEMATIC OF WASTE DUMP



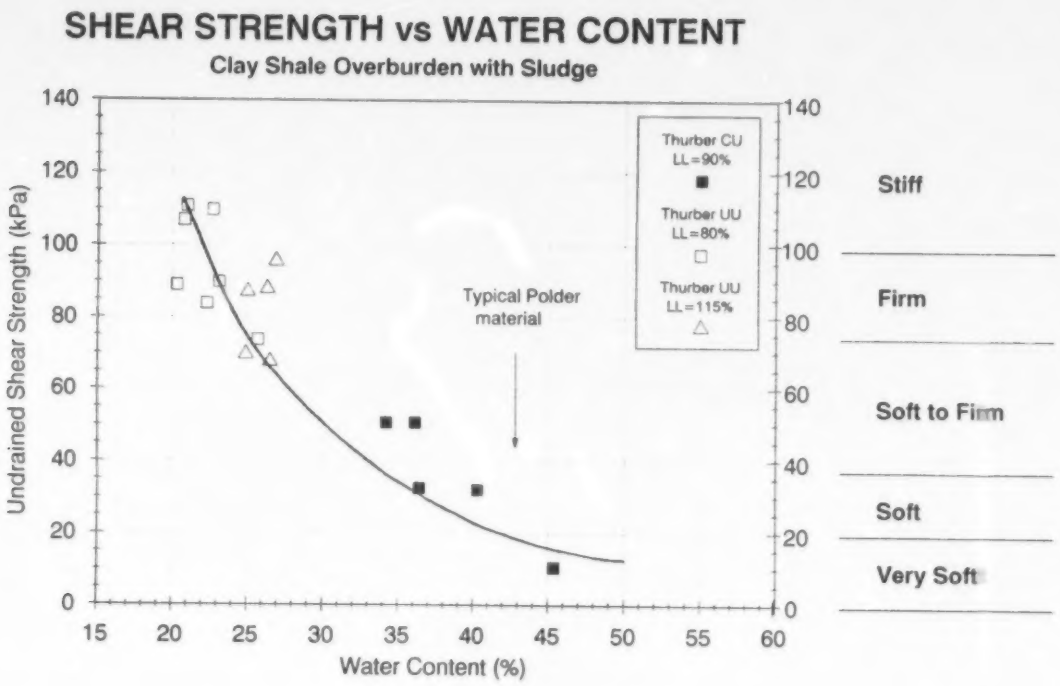


Figure 5. Shear Strength/Water Content Relationship (I).

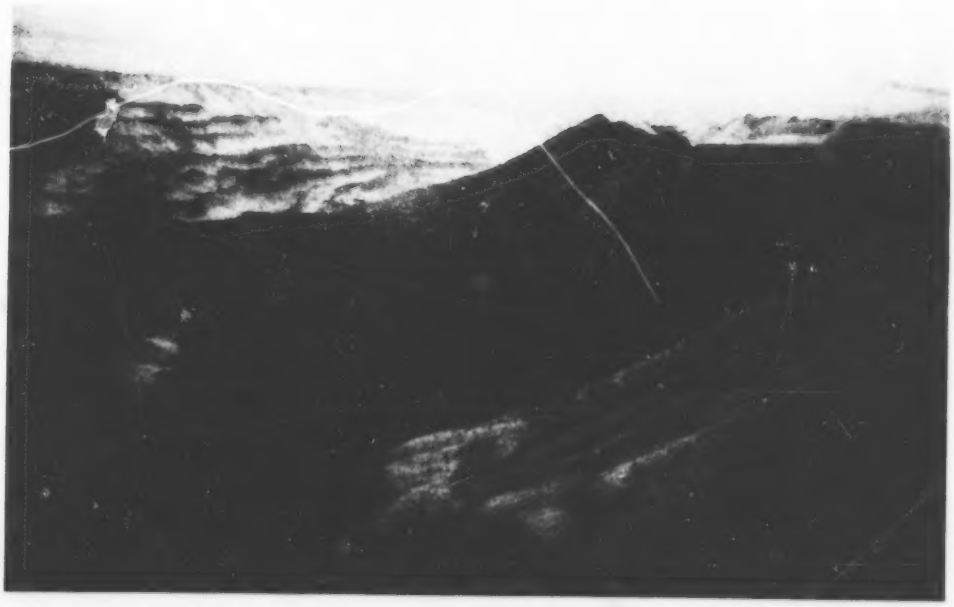


Figure 6. Limiting Height at Hambach Mine, Germany.

Figure 7. Overburden/Sludge Test Pits.

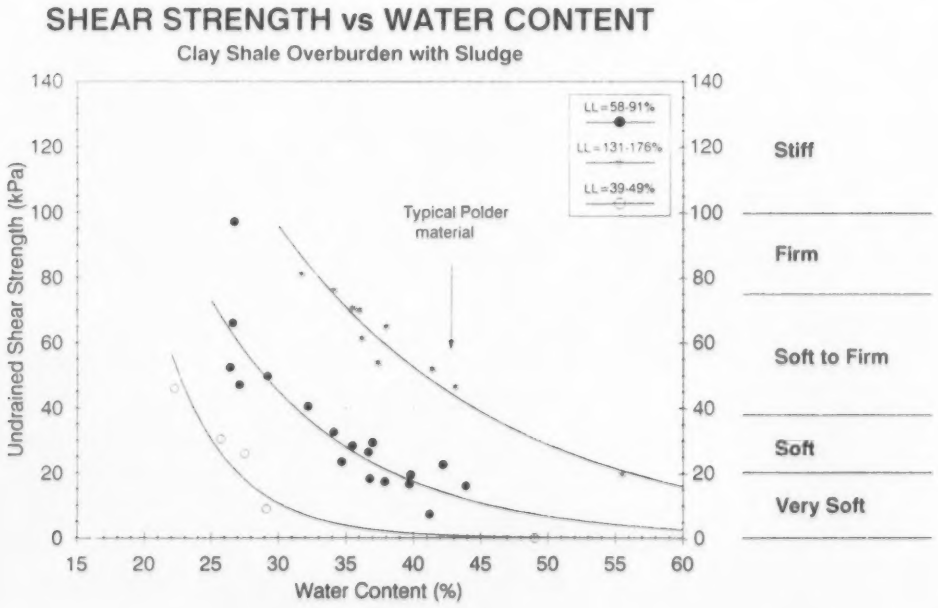


Figure 8. Shear Strength/Water Content Relationship (II).

Figure 9. Limiting Height Cone.

Figure 10. Operations Scale Truck/Dozer Mixing.

Figure 11. Completed Polder Overlain by Bearing Layer.

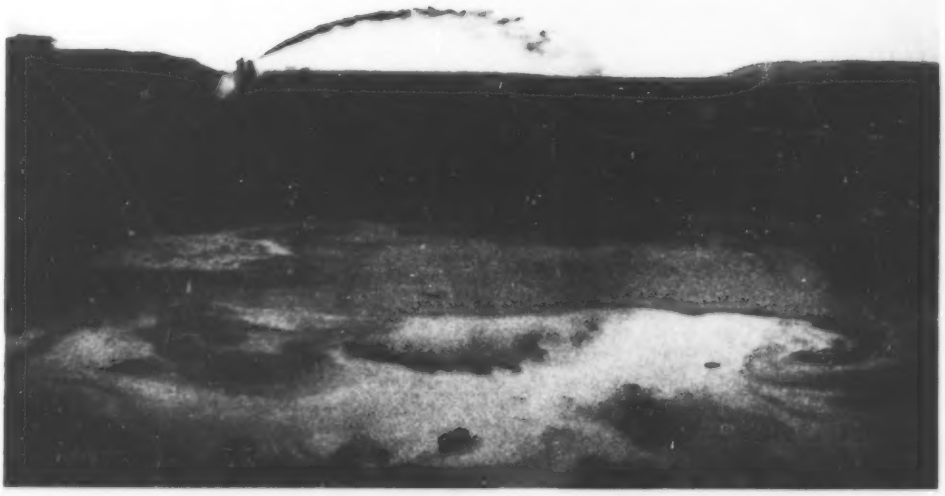


Figure 12. Spray Technique for Mixing.

Figure 13. Spreader Technique for Mixing.

The Global Warming Problem

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Strategies For The Fossil Fuels Industries Under The Threat Of Global Climate Warming

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The Global Warming Problem

The notion that global warming and the resulting climatic effects may be the greatest threat now facing humanity has captured the attention of the public at all levels from school children to senior political figures in much of the western world. The heads of state of the Soviet Union, the U.S., the U.K., Norway, and our own Prime Minister have all called for international action on the issue, and a meeting organized by President Mitterand and other European leaders last year recommended that the United Nations be given supranational authority to regulate activities that are identified as causes of global warming.

Since the combustion of fossil fuels is usually identified as the biggest single source of the 'greenhouse gases' that are blamed for the warming effect, I think the first question most of us at this Seminar would like to have answered is whether global warming really is a serious threat, in which case we should be preparing ourselves for some of the far-reaching measures that are being proposed to curb greenhouse gas emissions. Or is it possible that global warming may yet be found to be a minor problem, or that the apparent climate trends may not even be due to greenhouse warming?

Unfortunately, this is exactly the question that cannot be answered with certainty at our present state of knowledge. What can be said is that the majority of the scientists working in this field have become convinced that the effect is real and potentially serious, and that so far the evidence supporting this view seems to be increasing rather than decreasing. This still leaves room for considerable differences of opinion as to how serious that effects will actually be, and as to what action should be taken.

It may be useful to spend a few minutes reviewing the factual evidence for global warming, and the projections that have been made by computer simulation and other indirect methods. First off, there is no question that the 'greenhouse effect' itself is real, for ironically enough, it is the process which makes our planet habitable in the first place. If it were not for the infrared absorbing gases such as carbon dioxide and water vapor which are naturally present in our atmosphere, the average global temperature would be about −18° instead of the +15° it is now. We also know from actual measurements over a number of years that the concentrations of most of the greenhouse gases in the atmosphere are increasing. Consequently the average temperature has to increase, unless there is some unknown factor external to the system that could cancel out the effect.

Direct verification of the greenhouse warming effect by correlating temperature records with the increase in concentration of greenhouse gases is complicated by the fact that we are looking for a relatively small effect in a very 'noisy' climate record. The observable increase in average global temperature since greenhouse gas concentrations started rising appreciably in the middle of the last century is only 0.5± 0.2°C. Not surprisingly, the validity of an observed temperature increase of less than half a degree per century has been questioned on several grounds, although a recent and very sophisticated analysis by Bell Laboratories indicates that there is a statistically significant correlation between temperature and carbon dioxide concentration. A study just completed by the Alberta Research Council suggests that temperatures in Alberta have risen by an average of 0.5° per decade over the past 30 years. This is considerably higher than the global average, which is consistent with model predictions that warming effects will be greater at higher latitudes. A more exotic source of information is the analysis of deep ice cores from the Antarctic, which show a remarkably good correlation between temperature and atmospheric content of carbon dioxide and methane over the past 160,000 years.

Almost everything else you read about global warming, such as the projected temperature rise from future growth in greenhouse gas emissions and the resulting climatic effects, are based on computer simulations and analogies with natural climate fluctuation. The numerical models used to simulate global atmospheric effects are quite complex as a result of the many interacting processes in the atmosphere – ocean – land surface – ice surface system, and a large number of grid points is required for even a relatively coarse 3-D representation of the global atmosphere. While they are continually being improved, it is generally acknowledged that the present models do not fully represent all of the factors which shape our climate, particularly at the local level. Nevertheless, the climate modelling community seems confident that the results obtained are at least directionally correct. The models are verified by using them to predict current climatic conditions from known parameters; this they do quite well on a global basis but rather poorly on the regional level.

When they are used to simulate the temperature rise which should have resulted from the 25% increase in effective concentration of greenhouse gases since 1850, most models predict a global temperature rise of about 1° instead of the 0.5° observed. This is actually not bad agreement considering the uncertainty in both figures, but it does suggest that the models tend to overestimate rather than underestimate the effect. It is also possible that the warming is simply being delayed longer than predicted.

Predictions of future temperature increases are usually made for a doubling of the effective concentration of greenhouse gases, which is expected to be reached between 2030 and 2050, depending on the rates of growth in energy consumption and land clearing. The average global temperature increase predicted by the various models ranges from 2° to 5°, and it could take up to several decades after concentrations doubled to reach the maximum warming effect. While this does not appear to be a very large temperature change, it is worth noting that even at the peak of the ice age the average global temperature was only about 5° colder than now. The warming would also take place something like 100 times as fast as previous temperature changes; this could make it difficult for many of the natural systems to adjust, and could also lead to amplified temperature swings from positive feedback mechanisms in the system.

The large-scale climatic effects which are predicted as a result of global warming include the drying out of the continental interiors and a rise in sea level, which would have a decidedly unfavorable net impact worldwide. However, as I mentioned a few minutes ago, the current models are not capable of predicting regional changes in such critical parameters as precipitation reliably enough to say whether the effects on Alberta agriculture would be good or bad. If the amount and timing of precipitation remained adequate, or if irrigation were available, an increase in temperature and carbon dioxide concentration would be very beneficial to plant growth.

I would next like to review the various emissions that contribute to the global warming effect, where they come from, and what might be done to control them. The contribution of any gas to greenhouse warming obviously depends on its concentration in the atmosphere, but also on its effectiveness as an infrared absorber. Carbon dioxide is currently responsible for a little over half of the total greenhouse warming, and the next three in order of importance are methane, chlorofluorocarbons, and nitrous oxide. The concentrations of some of these gases are increasing more rapidly than carbon dioxide, and their collective warming effect is expected to exceed that of carbon dioxide by 2030.

The concentration of any greenhouse gas will depend on its rate of emission to the atmosphere and also on the rate at which it is destroyed or removed from the atmosphere. In the case of CO_2, the principal man-made sources are fossil fuel combustion, which emits about 5 billion tons per year globally, and deforestation which contributes an estimated 1 to 2 billion tons per year. However, this 6 or 7 billion tons per year is small in comparison to the natural cycles of CO_2 production and removal. About 110 billion tons per year are removed from the atmosphere by growing plants, and all but a very small part of this is returned to the atmosphere by respiration and by decay of plant material. Similarly, about 93 billion tons per year are removed by biological and chemical processes in the oceans, and 90 billion tons are returned to the atmosphere. The overall effect is that only about 3 billion out of the 6 or 7 billion tons of man-made CO_2 emitted annually actually accumulates in the atmosphere.

Methane is released to the atmosphere by various fossil fuel related activities such as oil and gas field operations, leakage from gas distribution systems, coal mining, and incomplete combustion of fuels. However, these appear to represent only about 1% of the methane emissions associated with other human activities such as rice cultivation, cattle raising, and landfills. I'm sure you've heard that Alberta's cattle produce about 100,000 tons of methane per year, which is of the same order as our total fossil fuel related emissions. There are also large but poorly-quantified natural emissions from anaerobic decay of vegetation in swamps and waterlogged soils. The principal mechanism for methane removal from the atmosphere is natural oxidation, eventually producing carbon dioxide.

Chlorofluorocarbons are entirely man-made and are used for a variety of applications such as

refrigerants, aerosol propellants, degreasing, and foamed plastics. Once released to the atmosphere the only significant removal process is photochemical decomposition in the upper atmosphere, which in turn leads to ozone destruction by free chlorine atoms. There is already strong pressure for a drastic reduction in chlorofluorocarbon emissions globally, which would also reduce their contribution to greenhouse warming.

Nitrous oxide is produced to some extent in the combustion of fuels, particularly plant material. However, this is a minor source compared to microbial decomposition of nitrogen fertilizers in the soil, and to release from freshly-cleared land. Most of the NO_x produced by combustion is nitric oxide and nitrogen dioxide which have very short lifetimes in the atmosphere.

Turning now to methods of reducing the emissions of the various greenhouse gases, the carbon dioxide emissions from combustion of fossil fuels can obviously be eliminated by switching to non-fossil energy sources such as nuclear or hydroelectric energy, or biomass fuels. However, it is also possible tc reduce carbon dioxide emissions while continuing to use fossil fuels by such methods as increasing the utilization efficiency to decrease the amount of fuel required for a given task; substituting fuels with higher hydrogen: carbon ratios to produce less carbon dioxide for a given energy production; converting heavier fuels to lighter fuels by hydrocracking or gasification to obtain a higher hydrogen; carbon ratio; capturing and using or disposing of the carbon dioxide from flue gas; and reducing the emissions associated with the production, processing, and transportation of fuels.

Reforestation and other methods of increasing the growth of vegetation would remove carbon dioxide from the atmosphere to yield a net decrease in carbon dioxide emissions. Discouragement of land clearing and waste burning, increased forest fire control, and productive use of wood and agricultural wastes instead of allowing them to decay would avoid the return of carbon dioxide to the atmosphere from carbon now tied up in plant material.

There are no obvious methods of limiting the build-up of methane in the atmosphere other than limiting emissions. This would be technically feasible for many of the emissions associated with oil and gas operations, and it would also be possible to collect at least part of the methane from landfills, coal mines, sewage disposal plants, and animal wastes. Even if the gas were simply flared on-site, the resulting carbon dioxide would have only one-twentieth the warming effect of the original methane. However, these emissions only represent a small fraction of the methane produced by agricultural operations and by decay of vegetation. Consequently any large reduction in methane emissions would probably require major changes in agricultural practices, which could have serious implications for global food supply.

As I mentioned earlier, chlorofluorocarbon emissions will probably be subjected to increasingly strict controls in any case, as a result of their connection with ozone layer depletion. Nitrous oxide emissions could be reduced to a small extent by improved combustion or reduced use of certain fuels. However, like methane, the major emissions are associated with agricultural operations and would be difficult to control.

This brief review of methods of controlling greenhouse gas emissions certainly suggests that more attention should be given to emissions other than carbon dioxide and to carbon dioxide emissions from sources other than fossil fuel combustion. Unfortunately any major reductions in these other areas will involve substantial technical or political problems, so fossil fuel combustion is likely to remain a popular target of programs designed to reduce greenhouse gas emissions.

To summarize my part of the presentation, the weight of evidence and scientific opinion suggests that global warming from the build-up of greenhouse gases in the atmosphere is quite probable, although there is considerable uncertainty as to the rate and magnitude of the warming. The over-all effect of the resulting climatic changes is likely to be negative on a global basis but could be favorable for some regions, quite possibly including Western Canada.

Combustion of fossil fuels contributes less than half of the total greenhouse effect, but fossil fuel use is likely to be a major target of measures to control global warming because of their greater susceptibility to regulation. However, conversion to alternative energy sources should not be looked on as the only solution, since there are several ways of reducing carbon dioxide emissions while continuing to use fossil fuels.

As a couple of general observations, it is often stated that we cannot afford to wait until global warming becomes serious since the effects may then be irreversible, so we should initiate action immediately. While there should be no unnecessary delay, we do have 40 years before we reach the crisis stage even under the most pessimistic scenario, so I believe that we have time to carry out whatever further studies of the various alternatives may be needed to decide on the most rational and productive courses of action. It is also worth noting that Canada only contributes 2% of the current global emissions of carbon dioxide, and that the less-developed countries can be expected to increase their emissions by more than Canada could reduce its own. Our most useful contribution to the avoidance of global warming may well be to provide other countries with the technology needed to increase their energy production without increasing their greenhouse gas emissions.

Strategies For The Fossil Fuels Industries Under The Threat Of Global Climate Warming

Taken as an isolated social issue, it would be extremely difficult to understand why the so-called Greenhouse Effect has assumed such broad international importance especially in view of the somewhat shaky scientific foundation upon which the concept is based. Certainly there have been many scientific theories in the past,, having broad societal implications, and erected on a more solid base of validatable data, which have later been shown to be completely wrong. Why then has the Greenhouse Effect achieved such prominence in our present world community?

To answer this question we must examine public attitudes toward advancing technology, especially since the advent of the nuclear age which began with massive human destruction in the forties. These public perceptions of science and technology have been created out of many quite justifiable fears of the evil effects that some new discoveries might visit upon society.

There have been many polls taken of these public attitudes in the past forty years, and they all show important components of distrust and fear in the general public perceptions of the effects of new advances in science and technology upon mankind.

The reasons for these negative attitudes are not far to seek.

The Damocletian sword of potential nuclear annihilation has been, of course, a major factor in determining public opinion about science and technology. Fortunately there seems to be grounds for modest optimism on this issue in very recent times. However, on related nuclear problems, such as the safe disposal of radioactive wastes from nuclear power plants, as well as the long-term safety of such plants, public skepticism is very apparent in public policy decisions in these areas.

There are many other such developments which have contributed to the deep-seated concerns which the general public feels toward science and technology. Genetic engineering,for example, triggers disturbing questions in the minds of many of us. Similarly pollsters have clearly shown that the increasing role taken by microprocessor-controlled systems in our society has raised fears about employment, and the sanctity of the individual.

However, most relevant to our present consideration is the impact which industrial technology has had upon the habitability of our planet. Indeed if we were to choose two words which most aptly represent our times, they would likely be 'environment' and 'pollution'. And it is now becoming abundantly clear that environmental concerns are the basis for many major political changes in our society.

It was in a society deeply worried about the worsening state of our environment that research scientists and engineers began sharing with the media their evidence that the mean temperature of the earth is likely rising, as a result of the accelerating buildup of greenhouse gases, and some of the alarming consequences which might ensue. In a world conditioned to the threat of impending global catastrophes from a myriad of causes, it is understandable why the spectre of global climate warming could be accepted almost without question by the general public. And as a result, political action followed rapidly after the pronouncements of climatologists and related researchers involved in determining how the so-called greenhouse gases might be affecting our climate on a world scale.

It is now abundantly clear that, with the exception, perhaps, of the third world countries, global climate warming has become a major international issue with profound implications for our fossil fuels industries.

This is a rather unique situation in the sense that these industries must now be seen to be responding to forces which are presumed to be changing our climate. Further research, however, may lead to markedly new interpretations of these climatic influences. And therefore courses of action taken by the industries must be flexible and designed to serve a number of environmental purposes, and also be compatible with their own economic imperatives.

There is no doubt that it is in the best interests of the fossil fuels industries to be seen to be taking the Greenhouse Effect very seriously. In fact it would markedly improve the image of this industrial group in the eyes of the public if a leadership role was taken by them in this matter. This could be accomplished by sponsoring research at universities and other research organizations to improve our understanding of global climate warming, , and in addition the industries could promote programs leading to a greater public understanding of this complex field of knowledge. Such initiatives would result in a better cooperation between governments and the industries in devising realistic legislation for controlling the emissions of greenhouse gases into the atmosphere.

The practical problem for the coal and petroleum industries will be to find methods for producing materials which will release less CO_2, and any controlling legislation will likely be along such lines.

It has already been pointed out, in the preceding presentation, that Canada is a relatively minor contributor to the global production of CO_2. Nevertheless national policies in this area will likely be patterned along international lines, and restrictive legislation similar to countries that are larger greenhouse gas producers will very probably be enacted.

In many ways this challenge to the fossil fuels

industries may prove to be more of a benefit than at first appears, because it will undoubtedly require that greater emphasis be placed on product diversification than has been done in the past.

It is fortunate that the petroleum industry is already devoting significant R&D efforts to high-conversion upgrading to reduce carbon rejection and improve liquid yields, for economic and environmental reasons, since these processes result in products with lower CO_2 emissions per unit of energy produced.

It has been said on a number of occasions that petroleum is far too valuable as a reservoir of new chemicals to be simply burned as a fuel. The present situation with respect to potential global warming gives a new importance to this statement.And here it should be noted that bitumen is an especially rich resource from a chemical standpoint. What is now almost imperative is that greater emphasis be placed on non-fuel uses for petroleum products. This clearly should be a major thrust in product diversification for the fossil fuels industries in general. In short, these industries must place an increasing emphasis on the chemical product potential of their raw materials. From an environmental standpoint, one obvious area of chemically-oriented research which the fossil fuels industries should address involves the enormous market for solvents which do not damage the environment.

If we assume that the climate scenario unfolds in accordance with the predictions of the climatologists, the fossil fuels industries will inevitably therefore be forced to make profound changes in their corporate strategies.

And it is appropriate at this point to mention that it is not just the Greenhouse Effect which will negatively impact on petroleum-based fuels. The exhaust from internal combustion engines has long been recognized as a major contributor to general atmospheric pollution, especially in large cities. This has stimulated a great deal of research into other methods of locomotion, and it appears now that recent developments in electric motor design, and in the manufacture of higher-capacity batteries will make electric vehicles significant contenders in the automotive field of the future.There is a major applied research effort in progress at the present time, designed to produce fast-rechargeable,higher-capacity batteries, of compact design, and this is the main hurdle impeding the commercial competitiveness of electric vehicles. All of the major automobile manufacturers are heavily involved in electric vehicle research, and it seems inevitable that this type of conveyance will progressively reduce the need for petroleum-based fuels in the future. The environmental advantages of electric vehicles are so compelling, when compared to present automobiles, that they seem assured of a significant share of the future vehicle market.

In conclusion, there is mounting evidence that the threat of global climate warming is going to be taken very seriously by all nations, with the possible exception of some third world countries.

The impact on the fossil fuels industries, in terms of restrictive national and international legislation, will almost certainly be related to limits on the use of CO_2-producing fuels.

Another very probable technological development which will also reduce the demand for current motor vehicle fuels is the production of electric vehicles using new, high-capacity, battery technology.

In order to prepare for such probable reductions in the future demand for current fossil fuels, these industries should consider making major changes in their corporate strategies in the direction of placing an increasing emphasis on the production of fuels richer in hydrogen, which generate less CO_2 per unit of energy produced, and also on a greater exploitation of the chemical potential of their resources, to make products for a vast range of non-fuel uses.